Energy, Mines and Resources Canada
Énergie, Mines et Ressources Canada

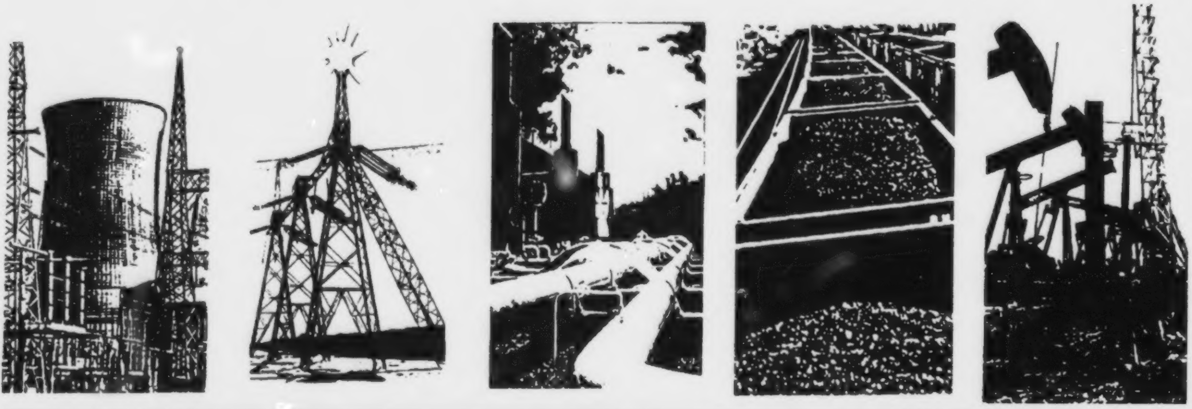
2020 VISION

1988 - 2020

WORKING PAPER

PREPARED BY

ENERGY AND FISCAL ANALYSIS DIVISION



ENERGY, MINES & RESOURCES CANADA

Canadä

2020 VISION

CANADA'S LONG TERM ENERGY OUTLOOK

WORKING PAPER

PREPARED BY

ENERGY AND FISCAL ANALYSIS DIVISION

ECONOMIC AND FINANCIAL ANALYSIS BRANCH

ENERGY, MINES AND RESOURCES CANADA

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PREFACE

The 1989 issue of Energy Outlook is similar in approach to the 1988 issue. Again this year, two world oil price scenarios were developed: a reference case, US$18/bbl oil price to $25/bbl by the year 2000 and flat thereafter; and an alternative case, US$15/bbl to $20/bbl by 2005. The alternative also incorporates a greater economic growth rate (by 15 per cent) than under the reference case.

The results are based on Energy, Mines and Resources Canada's (EMR) Inter-Fuel Substitution Demand model (IFSD), which incorporates the electricity-based Utility Generation Expansion (UGENEX) model. To maintain the reliability of our forecast, we updated our database through 1987, re-estimated market share equations and re-specified some behaviourial equations.

In developing our oil supply forecasts, consideration was given to available information on geology, engineering and the economic aspects of various sources of supplies which are consistent with the forecasting framework. The Oil and Gas Supply Impact Model (OGSIM), a modelling framework which relates industry cash flow to investment and ultimately to reserve additions, was used to ensure that projected supply can be achieved with the funds available to the industry for investment.

The main difference from last year's outlook is that our forecast now extends to the year 2020. This was seen as desirable because planning for such factors as pipelines and electrical generation facilities requires a long lead time. It was also desirable to determine whether our demand-supply balances were sustainable beyond 2005, the final year of last year's forecast.

Of course, our ability to infer the evolution of energy supply, demand and price 30 years into the future based on historical behaviour and theory is quite limited. Undoubtedly changes in the underlying technological assumptions (which can be considered to be fairly stable over a 10 to 15 year period) could significantly alter some of our key relationships in this longer term perspective. Nonetheless we believe it is valuable to have a reference view of the longer term, both to understand better the trends implicit in our outlook to the end of the century and to identify, at an early stage, the issues which are likely to arise in the longer term.

One such set of issues concerns the environmental implications of energy production and use. We are now at a very early stage in trying to define these issues. As a result, policies and programs to deal with environmental objectives are included to only a limited extent (i.e. in the electrical generation sector) in our outlook. In general, the outlook does not reflect any significant changes in policy framework. Rather the purpose of the forecast is to provide a reference against which impacts of alternative policies can be assessed.

Chapters II to IV of this report examine the basic assumptions underlying the forecast. Chapter V provides an analysis of the forecast results as they affect energy demand. Chapters VI through IX look at the supply side of the energy picture. The final chapter is a brief overview of environmental issues. (For detailed results in table form of the reference and alternative case forecasts, refer to appendices.)

The views expressed or implicit in this document are not necessarily those of the Government or of the Department, and no inferences should be drawn from this paper concerning the current or future status of any policy or program.

"2020 Vision" was prepared under the direction of my predecessor, Bill Jarvis. A study of this magnitude is, by its nature, the product of a team effort. Among the many contributors, the following deserve special mention: Ram Sahi, who guided and coordinated the analysis, Michel Bérubé, André Bourbeau, Al Coombs, Wally Geekie, Sushama Gera, Hertsel Labib, Jai Persaud, Yvon Sabourin and Michel Théoret. Valuable assistance was provided by the Oil and Natural Gas Branch, the Electrical Energy Branch, the Coal Division, the Office of Environmental Affairs and the Energy Programs Sector of this Department. The Information Systems Section of our branch played a key role in the formatting and production of the document.

The tables in the appendices present a selection of the result of the outlook process. Further detail is available, and the Division would be pleased to discuss any aspects of the forecast with interested parties.

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Winter 1990

(aussi disponible en français)

I. EXECUTIVE SUMMARY

Assumptions

- To reflect the uncertainty surrounding future world oil prices, two oil price scenarios are assumed: reference and alternative. The reference case assumes oil prices rising from the current level of about US$18 to $25/bbl (1989$) by 2000 and then remaining flat. This scenario assumes a high growth in energy demand, OPEC discipline with low volumes, slower non-OPEC development and status quo government policy on oil product use. The alternative case, in which oil prices rise from US$15 to $20/bbl by 2005, assumes slower growth in oil demand, weak OPEC discipline, faster non-OPEC development and proactive government policy in most countries for restraining oil use.

- For the reference case, it is assumed that economic growth prospects become increasingly limited by labour force growth, increased international competition and the maintainence of real interest rates above historical levels. Real Gross Domestic Product (GDP) increases by an average 2.4 per cent over the forecast period. The alternative scenario assumes a rate of economic growth of 2.8 per cent per year, that is 15 per cent faster than that of the reference case .

- The projections herein do not reflect any significant changes in policy framework. Rather they provide a reference against which the impacts of alternative policies and programs can be assessed.

Prices

- Gas-oil parity at Toronto is set at 85 per cent in the reference case and 96 per cent in the alternative case.

- Due to surplus capacity, real electricity prices fall by 1.2 per cent per year until 1995, after which they firm-up as excess capacity is used.

- Coal prices are constant throughout the projection period.

- The Canadian dollar has been set at US$0.80 over the forecast period.

Demand

- The results of our reference case suggest that, by 2020, secondary energy demand will be 90 per cent higher than it is today. Although most of this increase will come from electricity, consumption of oil is projected to be 66 per cent higher than 1988 levels.

- End-use energy intensity decreases by 0.3 per cent per year over the forecast period.

- Electricity's share of secondary demand increases from 23 per cent in 1988 to 30 per cent in 2020.

- Net electricity exports increase by 58 per cent to 2005 and remain relatively flat thereafter.

- Natural gas' share of total secondary demand stays constant at 25 per cent, while oil's share drops from 40 to 35 per cent, with most of this decline occurring in the 1990s.

- In the alternative scenario, energy demand by the year 2020 is 13 per cent higher than in the reference case. Energy consumption is up in all sectors, but more so in those that are dependent on oil, such as transportation and industrial. Results of the alternative scenario show that the income effect is greater than the price effect.

Supply

- Under the reference case, oil supply in 2020 (at 2 mmb/d) will be 15 per cent higher than the 1988 level. Most of this increase is due to the development of bitumen projects, synthetic plants and the frontiers. Despite increased production, Canada becomes a net oil importer by 2010 (up to 470 mb/d by 2020).

- Under the alternative case, oil supply in 2020 will be 10 per cent lower than the current level. Canada becomes a net importer of oil by 1993 (up to 1330 mb/d by 2020).

- Sufficient gas supplies are available to meet increasing domestic and export demand under both price scenarios. Under the reference case, over 500 bcf of excess supply exist. Under the alternative case, relatively higher gas to oil prices are needed to maintain the balance between supply and demand.

- In the reference case, natural gas exports are assumed to increase to 2.1 tcf by 2000 and remain flat to 2020 (1.7 tcf in the alternative case).

- Canada's electricity generating capacity is expected to double by 2020. Hydro's share should be 50 per cent and nuclear's share 20 per cent (compared to 56 and 12 per cent respectively today).

II. WORLD OIL PRICE OUTLOOK

1. Introduction

Any forecasting exercise must begin with the development of a solid and logical set of assumptions. Chief among these assumptions, when forecasting energy supply and demand, are world oil prices and the macro economic environment. While the latter is the subject of a subsequent chapter, this chapter outlines (and justifies) the world oil price scenarios that were chosen for this outlook.

Since the first oil price shock in 1973, volatility and uncertainty have been the main characteristics of international oil prices. Although the situation has been relatively stable for some time, and is expected to remain so for the foreseeable future, some unexpected event could precipitate another international crisis.

It would be inappropriate to develop a single price scenario, given the lingering uncertainty in world oil markets and the key role played by price expectations in technological development and resource availability. Thus, two scenarios were developed, each reflecting a different view of the evolution of supply and demand trends. The reference case assumes that the recent increases in the demand for OPEC oil (as a result of strong growth in world oil demand) and the stagnancy of non-OPEC production will continue for a few more years. As excess productive capacity for most energy forms is used up in non-OPEC countries, oil prices are assumed to rise to at least US$25/bbl, which is the estimated cost of back-stop technology. In the alternative scenario, it is assumed that the current stagnancy of non-OPEC production and strength of world oil demand are aberrations. With oil demand tapering off and non-OPEC production picking up, prices are assumed to be softer.

2. Two Scenarios

For the purpose of the present forecast, it was decided to develop two world oil price scenarios. Although the range of possible future oil prices is wide, almost limitless even, the range that may be considered reasonable, under current and anticipated circumstances, is much narrower. Chart 2.1 shows the upper and lower bounds (US$30/bbl and US$15/bbl, 1989 $) between which oil prices are expected to lie. Below US$15/bbl, demand should increase steadily and non-OPEC supply should fall. Above US$30/bbl, the reverse should occur. Thus, market forces should constrain world oil prices well within these bounds over the long term.

In the reference case, the real world oil price is assumed to be US$18/bbl in 1990, to climb steadily at an annual rate of just under 3.5 per cent to US$25/bbl by 2000, and to remain flat thereafter. In the alternative case, it is assumed that the real international price of oil is about US$15/bbl in 1990, climbs by an annual rate of about one per cent to reach US$20 in 2005, and remains flat thereafter (see table 2.1).

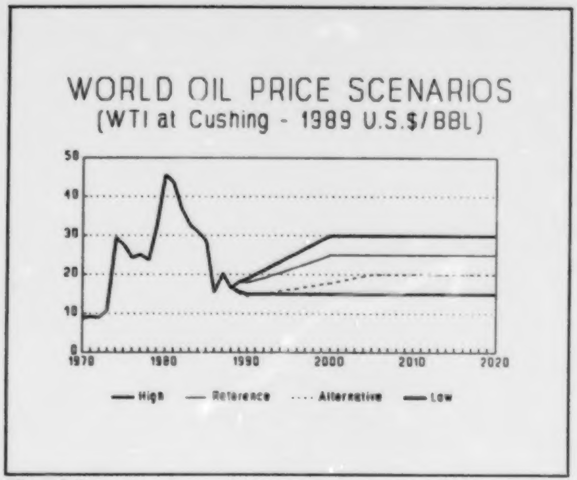

Chart 2.1

Table 2.1

REAL PRICE OF WEST TEXAS INTERMEDIATE

(1989 US $/bbl)

	Hist. 1988	Forecast 1990	1995	2000	2005	2020
Reference	16.62	18.00	21.21	25.00	25.00	25.00
Alternative	16.62	14.40	16.08	17.94	20.00	20.00

(% Average Annual Growth Rate)

	1988-95	1995-00	2000-05	2000-20
Reference	3.5	3.3	0.0	0.0
Alternative	-0.5	2.2	2.2	0.0

Reference Case

The main characteristics underlying the reference case are:

- high worldwide economic and oil demand growth;
- OPEC discipline -- restricted crude production at around 26 MMB/D by 2000;
- low level of non-OPEC resource development;
- low level of oil exports from Centrally Planned Economies (CPEs);
- no severe environmental restrictions on oil products usage;
- modest change in oil products taxes.

Large oil resources worldwide will continue to be a key factor restraining the level of oil prices. Current EMR estimates place conventional oil resources worldwide at about two trillion barrels (table 2.2). These estimates, which are thought to be conservative, imply a supply of close to 100 years at 1988 production rates. When non-conventional resources, such as tar sands, shale oil and enhanced oil recovery, are included, a further 1 to 1.5 trillion barrels are added to world reserves (45 to 70 years of supply).

Table 2.2

SOURCES OF LIQUID FUELS

Source:		Price('87 $US) $/BBL	Billions of Barrels	Years[1] of Supply
Known Reserves:	Middle East	1-5	667	33
	Rest of World	5-12	335	15
Additional Mid. East Conventional		3-7	100-200	5-9
Additional Rest of World Conventional (non-CPEs)		12-20	200-300	9-14
Additional CPEs		12-20	100-200	5-9
Deep Offshore/Frontier		15-30	200-300	9-14
TOTAL CONVENTIONAL			1600-2000	76-94
Tar Sands:	Canada	15-35	300-500	14-23
	Orinoco	"	150-250	7-11
Enhanced Oil Recovery		15-45	300-500	14-23
Shale Oil:	Current Technology	30-50	100	5
	Advanced Technology	40-50	100-200	5-9
Natural Gas >>> Gasoline		25-30	?	?
Coal >>>> Gasoline		30-50	?	?

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[1] Years to supply world at 60 million b/d or 22 billion barrels per year.

With this potential world oil base, OPEC might find it counter-productive to force up oil prices to the point where they would encourage extensive non-OPEC oil exploration and development and substitution of oil by other fuels. Therefore, it is assumed that a real rate of growth of slightly more than three per cent per year over the long term (resulting in an oil price of around US$25 real) would allow OPEC to ensure adequate revenues for its member countries without triggering the kind of expansion of non-OPEC production that would threaten OPEC's strong influence on world oil markets.

Oil exports from CPEs are assumed to remain close to current levels, at least for the medium term. For this reason, they are not seen as a threat to oil price stability. While the Soviet Union's reserve to production ratio (R/P) has fallen steadily (to a current level of about 12 years), the recent priority given to the development of oil reserves should help the Soviets maintain their production levels. In addition, the U.S.S.R. has the largest gas reserves of any country in the world. This will allow it to substitute gas domestically and thus free-up more oil for export.

The rate of real oil price growth envisaged in this scenario is compatible with the strong growth in world oil demand during the last few years, which is expected to continue in the medium term. It is further assumed that, at least in the medium term, there will be no major technological discovery or improvement in efficiency that would undermine the charted course of oil demand.

A slightly different picture emerges in the long term. It is assumed that between 2005 and 2020, the real price of oil will remain flat. By that time, population and economic growth in western countries will have slowed, thus easing the growth in the demand for oil. It is also assumed that more non-OPEC, non-conventional oil production will come on stream. (Indeed, it is assumed that back-stop production is developed in order to keep prices from rising.) These two effects, one on the demand side and the other on the supply side, should combine to restrain the growth of oil prices.

Beginning in the 1990s, but more so in the ensuing periods, many oil importing countries are likely to take steps to restrain their oil demand growth. Policies to reduce oil demand growth could come about as a result of environmental concerns or as an answer to high oil import bills. This is another reason for maintaining prices flat beyond 2000.

Alternative Case

The alternative case assumes some combination of the following factors:

- low world economic and oil demand growth;
- OPEC strategy of high production (about 32 MMB/D by 2000) to accommodate the aspirations of its members and to discourage non-OPEC development;
- high non-OPEC resource development with improved technologies, together with stable or increasing exports from CPEs;
- proactive policies aimed at reducing oil demand in some high oil-consumption countries;
- severe environmental restrictions affecting oil consumption.

Two important factors distinguish the evolution of world oil prices in the alternative case from the reference case. First, it is assumed in the alternative case that OPEC wishes to increase its share of the world oil market in the long term by discouraging non-OPEC oil development. To achieve this goal, OPEC increases its level of production, thereby bringing about slower price growth. (An EMR study[1] suggests that the long term interests of OPEC countries with large reserves and small population are served better by lower prices and high production levels.) Second, it is now assumed that oil consuming countries, particularly those in the West, will implement measures aimed at reducing oil demand more than is the case in the reference scenario.

3. Conclusion

The two price scenarios described above have been chosen for this examination of Canadian energy demands and supplies for several reasons. The limiting cases outlined in (chart 2.1) are given much lower probabilities. The scenarios chosen are based on smooth price trends over time. It is likely that world oil prices will fluctuate significantly over the course of a year, over business cycles, or over even longer periods such as investment cycles. However, the timing and magnitude of such fluctuations are not predictable and, for most long term planning purposes, smooth extrapolations are probably more useful than arbitrary volatility.

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[1] A. Coombs and R. Sahi, "The World Oil Market and Views on World Oil Prices", EMR, February 1988.

III. DOMESTIC ENERGY PRICES

1. Crude Oil Prices

With the deregulation of the Canadian oil market in June 1985 (under the Western Accord), sales contracts for oil from domestic or foreign sources are no longer subject to volume restrictions and prices are negotiated by the buyer and seller. Given that Canada is a minor player on the international market, Canadian prices are determined by international supply and demand. Consequently, the Canadian price is the same as the world price, adjusted for transportation, quality and the exchange rate.

The bulk of Canadian crude exports to the United States -- more than 65 per cent of the total -- go to the Minnesota and Chicago markets. Canadian export prices should therefore be competitive with American West Texas Intermediate oil (WTI) in these markets.

In view of the increasing importance of North Sea oil in Canadian imports, Brent is clearly indicated as the reference price for Canadian import prices. The price of imported crude at Montreal is expected to track the price of North Sea Brent, adjusted for transportation costs, the exchange rate and quality differential.

In the IFSD model, regional refiners' acquisition costs increase at the same rate as world prices, with slight variations depending on region and quality. Pipeline tolls are projected to increase at half the rate of inflation. Oil products prices are projected by adding a margin for refining, distribution and marketing costs, as well as specific taxes for each oil product, to the refinery acquisition cost of crude (adjusted by a producer self-consumption factor). The margins are indexed to the rate of growth of the general price index. Taxes on oil products were adjusted to take into account the most recent changes in the April 1989 federal budget.

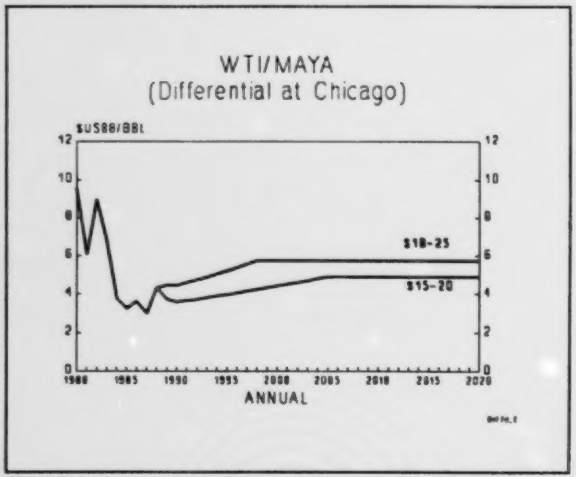

Chart 3.1

2. Oil Price Differentials

Price differentials between light and heavy crude are critical in analyzing the potential for domestic refinery investments and heavy crude oil and bitumen projects in Canada. For this outlook, the differential between light (38 API) and heavy (22 API) blends in Edmonton is assumed to be limited by the cost of adding new upgrading facilities. However, we expect that in the short to medium term, this differential, as shown in chart 3.1, will increase from its current level of US$4/bbl to nearly US$6/bbl (1989$). Above that level, refiners -- especially those from the U.S.-- would find it profitable to invest in upgrading facilities. This would prevent differentials from becoming larger, except for short periods of time.

3. Natural Gas Prices

Overview

Deregulation of the Canadian and U.S. natural gas markets occurred during a period of surplus supply and declining world oil prices. This resulted in a rapid drop in the price of gas on the North American market, creating strong competition between the various natural gas marketing agents and with alternative sources of energy.

The drop in natural gas prices discouraged exploration and stimulated demand. Consequently, the "gas bubble" seems to be dissipating. Prices are expected to remain stable in the short term because of previous contractual commitments. In the medium and long terms, gas prices are expected to rise as U.S. demand increases and supply remains limited because of a lack of exploration.

Regulatory Framework of the Domestic Market

In October 1985, the federal government and the producing provinces signed the Agreement on Natural Gas Markets and Prices. This agreement relaxed controls on exports and introduced, as of November 1, 1986, a deregulation process for Canadian natural gas prices. As a result, Canada went from a system of government-dictated prices to one in which prices are predominantly determined by the market, for gas sold both domestically and abroad. This necessitated changes in the marketing structures at the interprovincial level.

Regulatory relaxation encouraged many new participants to enter the market, which lead to increased price competition. The average field price in Alberta fell from $2.64/mcf in November 1986 to an annual average of $1.71/mcf in 1987 and $1.63/mcf in 1988, for a total drop of 38 per cent. The rapid increase in the number of direct sales partly explains the sharp drop in prices at the beginning of the deregulation process. The continued fall of the Alberta field price was due primarily to the appreciation of the Canadian dollar, as the field price in U.S. dollars was relatively stable during this period (chart 3.2).

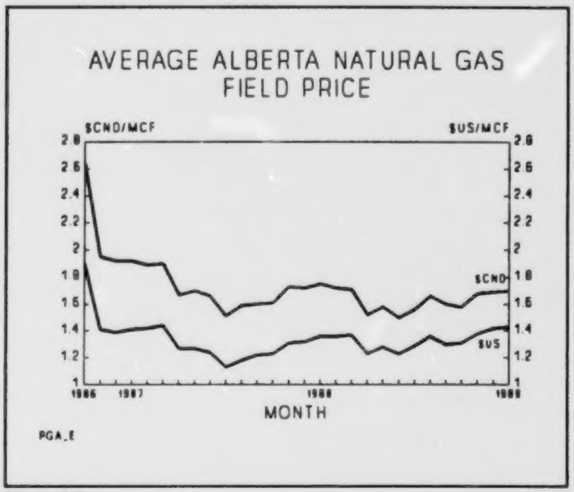

Chart 3.2

Although deregulation was introduced in November 1986, it has not yet resulted in a fully competitive environment. The Canadian natural gas market is experiencing transition problems.

In March 1988, the Government of Alberta announced its new natural gas marketing policy. Under this policy, all natural gas consumers would have access to direct sales, but consumers using natural gas for heating purposes (the core market) would have to sign long term contracts (10 to 15 years) in order to obtain supply security guarantees. As well, to have access to direct sales, consumers would have to order a minimum quantity of 35,000 GJ/year, a relatively large quantity for small users. The introduction of Alberta's new royalty system reduces the incentive for producers to offer lower-than-average prices.

Determination of Natural Gas Prices

As indicated, the goal of the current deregulation policy is to encourage competition. In a competitive market situation, two tendencies are inherent. First, the market price tends to adjust to the price of the last unit of the product sold. In Canada, this price can be interpreted to be the price of direct purchases by large industrial consumers and public utilities. Second, the market price reflects the price of the best and easiest substitute, which means that market forces will tend to equalize the prices of these two products (adjusted for efficiency of their energy content). For large industrial consumers, heavy fuel oil is the main alternative to natural gas (most of these consumers have equipment enabling them to convert quickly from natural gas to heavy fuel oil and vice versa). Under these circumstances, it can reasonably be expected that natural gas-heavy fuel oil competition in the industrial sector will determine the market price for natural gas in the reference scenario. In the alternative scenario, however, it is assumed that gas supply does not expand fast enough to meet demand. Gas will therefore gradually be withdrawn from its lowest-price uses and markets, and the price will rise relative to alternatives. Under the alternative scenario, a greater increase is assumed in gas demand in the U.S., due to environmental measures. For this reason, for the reference case, the direct sales price for natural gas is set at about 100 per cent parity with heavy fuel oil at the burner tip, and at 120 per cent for the alternative case.

Despite deregulation, wholesale prices of natural gas (the price less the distribution profit margin) continue to vary according to category. If all the objectives of the deregulation policy were achieved, these prices could be the same for all users except for differences attributable to load factors and length and type of contract. However, this would require natural gas sellers to compete as much among themselves as with substitute products, as well as equal negotiating power for all categories of purchasers. Since these conditions have not been met, as discussed below, significant price differentials are expected to continue in the natural gas market, particularly in the short and medium terms:

- In regard to the industrial sector, the system sales price of natural gas is expected to remain higher than the direct sales price as system sales include such services as storage, balancing and guaranteed peak-point supply, all of which must be reflected in the price.

- Core market consumers are expected to continue to pay a relatively higher wholesale price than industrial consumers, as they have access only to more expensive alternative energy sources (such as heating oil and electricity). They also have less flexibility in converting from one energy source to another.

- Export prices are expected to lead the average domestic prices as pipeline availability increases and surplus U.S. gas decreases.

In brief, natural gas prices are based on the assumption of sectoral gas-oil parity at Toronto. Market segmentation has also been taken into account. As a result, for most of the outlook period, parity between the average natural gas wholesale price and the refinery acquisition cost of crude at Toronto averages 85 and 95 per cent for the reference and alternative scenarios respectively.

4. Electricity prices

In both scenarios, electricity prices are expected to rise less rapidly over the projection period than oil and gas prices. Given the current surplus capacity, electricity prices are expected to increase at less than the inflation rate (four per cent) until 1995. After 1995, they are projected to rise more rapidly to meet the revenue requirements for the construction of new facilities.

As shown in table 3.1, end-use prices for electricity in Ontario and Quebec generally grow at a slower rate that end-user prices for oil product and natural gas, at least in the reference case. The results also show that electricity prices grow more slowly in the first years of the forecast. For example, Ontario[2] would experience a growth of 1.9 per cent (reference case) or 1.4 per cent (alternative case) between 1988 and 1995, as compared to 5.8 per cent or 5.9 per cent respectively between 1995 and 2005. The results obtained for Quebec also show a lower price growth before 1995, but to a lesser extent. After 2005, however, electricity prices grow at about the same rate as natural gas prices.

Table 3.1

SELECTED END-USE PRICES
Average Annual Growth Rates of Nominal Prices (%)

	Electricity			Natural Gas			Oil Products		
	1988-95	1995-05	2005-20	1988-95	1995-05	2005-20	1988-95	1995-05	2005-20
Reference case									
Ontario									
Residential	1.9	5.8	4.0	5.2	5.3	4.0	5.4	4.9	4.0
Industrial	1.9	5.8	4.0	5.0	6.0	4.0	7.5	6.0	4.0
Quebec									
Residential	3.6	4.1	3.5	4.9	5.0	4.0	5.6	4.9	4.0
Industrial	3.6	4.1	3.5	2.8	5.8	4.0	8.2	5.9	4.0
Alternative case									
Ontario									
Residential	1.4	5.9	3.9	4.4	5.1	4.0	3.5	5.0	4.0
Industrial	1.4	5.9	3.9	2.8	6.5	4.0	3.5	6.4	4.0
Quebec									
Residential	3.8	4.3	3.7	4.9	4.9	4.0	3.6	5.0	4.0
Industrial	3.8	4.3	3.7	2.8	6.3	4.0	3.6	6.5	4.0

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[2] Ontario Hydro and other Canadian utilities may choose to increase prices at the rate of inflation in the 1989-1995 period in order to even out future price increases and to improve their debt/equity positions.

5. Coal Prices

Most Canadian-produced coal sold on the domestic market is used in thermal power plants to generate electricity. Alberta, Saskatchewan and Nova Scotia are able to meet their own coal requirements but Ontario imports most of its coal from the U.S. (with transportation accounting for nearly 50 per cent of the cost of thermal coal, the proximity of American sources of supply make that country's coal less expensive in Ontario).

In the long term, the price of Canadian thermal coal is unlikely to grow at a faster rate than inflation because most coal mines are owned by utilities. American coal prices are also expected to remain relatively low given the glut on world coal markets. The exchange rate will play a role in determining the future price of Canadian coal since contracts are denominated in U.S. dollars. In 1988, for example, the increase in the world price was partially offset by the appreciation of the Canadian dollar.

Although most of the coking coal produced in Canada is exported, the metallurgy sector is still the second largest domestic consumer of coal. As steel plants are concentrated in Ontario, Canada imports nearly all of its coking coal. U.S. prices of coking coal are also likely to remain soft as a result of the expected slow growth of the steel market and of strong international competition.

Briefly, under both scenarios long term coal prices are expected to track the rate of inflation.

6. Inter-fuel Competition

Energy prices for the end-user sectors (i.e. the prices at the burner tip) vary widely both across and within regions, depending on the sector. Chart 3.3 provides the burner-tip prices (in real 1981 dollars) by sector for the reference scenario for Quebec and Ontario. (Ontario and Quebec are chosen for illustrative purposes because of the high volumes of energy used and the intensity of inter-fuel competition in these markets). These prices have been determined on the basis of the relative efficiency-adjusted energy content of the fuels[3]. For the industrial sector, electricity prices are based on a monthly load of 2.5 GWh, and are not representative of all industrial uses except with respect to the changes over time.

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[3] Energy efficiency assumptions used in this forecast are: for the residential sector, 65 per cent for heating oil and natural gas; for the commercial sector, heating oil, heavy fuel oil and natural gas adjustments are 70 per cent, 72 per cent and 68 per cent, respectively; and, for the industrial sector, heavy fuel oil and natural gas coefficients are 87 per cent and 85 per cent. For electricity, efficiency is assumed to be 100 percent for all sectors.

In each of the regions, the relative price of electricity to natural gas and fuel oil decreases. Gas-oil competition is relatively intense for the industrial sector of Ontario.

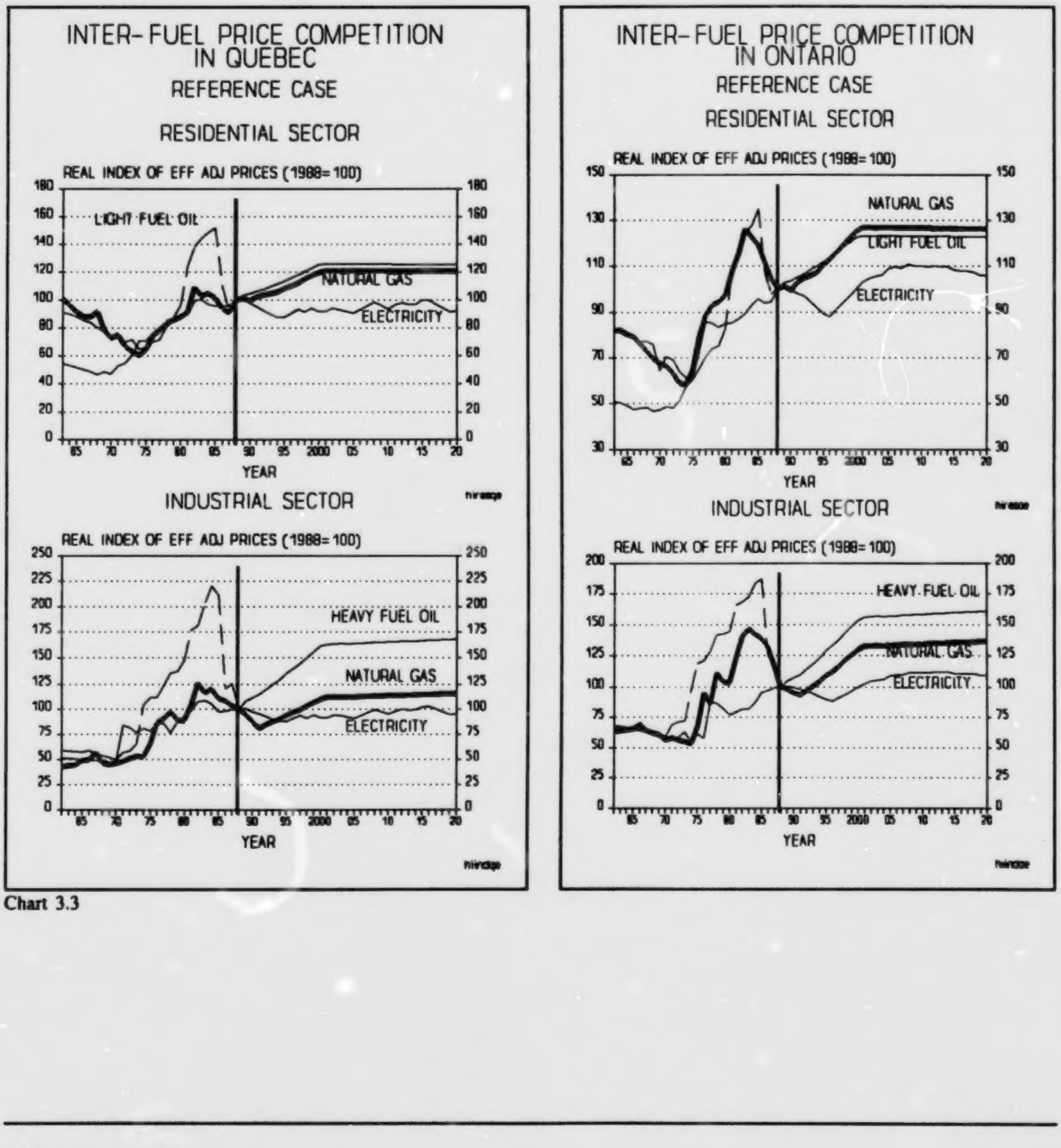

Chart 3.3

IV. MACROECONOMIC ASSUMPTIONS

1. Introduction

Along with prices, macro-economic and demographic assumptions are the main determinants of energy demand. While prices tend to influence short term demand and fuel shares, macro-economic and demographic assumptions help to establish the longer term evolution and pattern of demand.

This chapter looks at the main macro-economic assumptions that underlie the reference case and alternative scenario. They are based on Informetrica Limited's National Reference Outlook of October 1988.

2. Short Term Assumptions

Real GDP is assumed to grow at a rate of 2.4 percent in 1989, dropping to 1.5 per cent in 1990 and rising to 3.7 per cent in 1991 (chart 4.1). Throughout this period, consumer expenditures are assumed to be weak. It is also assumed that little growth will come from the trade sector. As for investment, it is assumed that the effects of high interest rates and lower rates of capacity utilization are offset by the benefits arising from free trade.

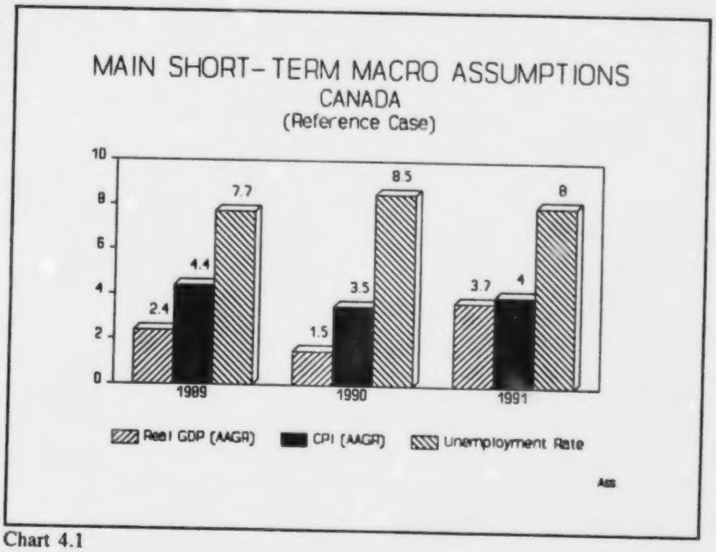

Chart 4.1

3. Long Term Assumptions

In the long term, it is assumed that growth prospects will become increasingly limited as population and labour force growth slows, international competition increases and real interest rates remain above historical levels (table 4.1). By extension, it is assumed that the Canadian economy will grow at a rate lower than in recent years. On the demographic side, population growth is projected to be slightly above one per cent per annum to 1995; thereafter, the rate of growth falls gradually through the remainder of the forecast period. This reflects a lower fertility rate, reduced immigration and the aging of the population. The fall in household growth will be less steep because, as the population ages, there will be an increasing number of single-person households.

Table 4.1

MAIN MACROECONOMIC ASSUMPTIONS - REFERENCE CASE

(CANADA)
(Average Annual Growth Rates)

	1988-95	1995-00	2000-05	2005-20	1988-20
Real GDP	2.3	2.4	2.5	2.3	2.4
Industrial RDP	2.6	2.9	3.1	2.7	2.8
Services RDP	2.1	2.1	2.1	1.7	1.9
CPI	3.9	4.1	4.1	4.0	4.0
US WPI	3.7	4.1	4.1	4.0	4.0
Employment	1.1	1.2	1.4	0.9	1.1
Total Population	1.1	0.9	0.8	0.6	0.8
Total Households	1.5	1.3	1.3	1.3	1.3
Labour Force	1.2	0.9	0.9	0.9	0.9

A flat US$0.80 exchange rate has been assumed for the entire forecast period under both price scenarios.

Given that Canada is a trading nation, the international economic situation is particularly important. Three factors are assumed to limit Canadian export growth over the forecast period: first, decelerating population growth should bring about a generally lower level of economic growth in OECD countries. In addition, it is assumed that U.S. economic growth will be further restrained, well into the 1990s by measures aimed at reducing the budget deficit. Assuming some success in achieving this objective, the end of the century could see an easing of monetary and fiscal restraints.

Second, it is assumed that Canada will face both stiffer competition for its products and changing markets as a result of the trend toward large trading blocs. Finally, commodity prices are expected to remain very soft, and perhaps even decline, due to worldwide moderate growth and increasing substitution of metal with non-metal products.

A key assumption in both the reference case and the alternative scenario is that free trade will have a beneficial impact on Canada: that there will be real income gains (as a result of lower prices) and large productivity gains in manufacturing (due to restructuring). As a consequence of free trade, the 1990s should see a large investment in capital stock. Given the above factors, real GDP is assumed to grow at an annual rate of approximately 2.5 per cent between 1990 and 2005, and 2.3 per cent between 2005 and 2020. It is also assumed that the Consumer Price Index will grow at an annual rate of around four per cent over the whole forecast period.

Generally, it is assumed that economic growth will track population growth (e.g. as population growth subsides, so does economic growth). We are therefore assuming lower levels of GDP and employment growth than recent historical levels. However, productivity growth is assumed to be closer to recent historical levels (except the 1975-1981 period), and is expected to offset the impact of slow population growth in the economy. (Productivity growth is a result of free trade and technological change).

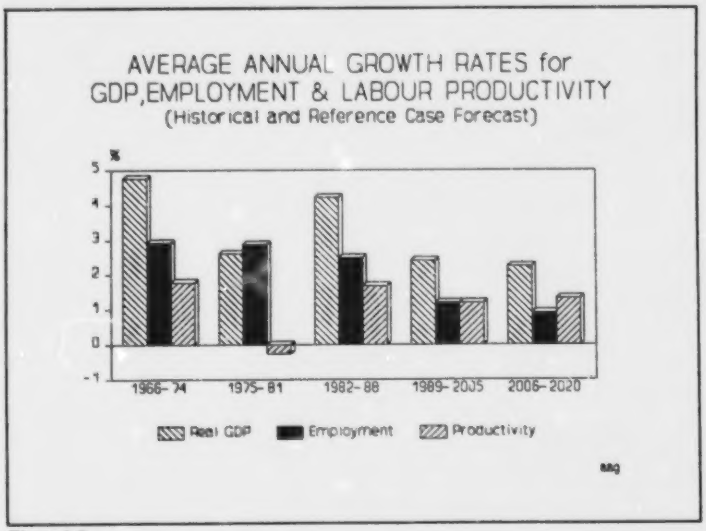

Chart 4.2

4. Provincial Outlook

It is assumed that provincial economic trends will basically follow the national trend. For example, the Atlantic provinces are assumed to see slower growth in 1989 and 1990, following in the footsteps of the U.S. and the rest of Canada. Beyond these years to the end of the century, the pace of economic growth will be more brisk, mostly due to the assumed construction of large projects such as Hibernia in Newfoundland and the fixed-link crossing between New Brunswick and Prince Edward Island. The latter will boost the tourism industry for those two provinces.

It is further assumed that Quebec will benefit from free trade. However, the province's large industrial sector (notably non-durables) will suffer from weaker consumer spending, as the economy begins to slow and, in the longer term, as population growth moderates. A major positive factor in the medium term is the planned development of additional hydroelectric capacity. In Ontario, productivity gains in the manufacturing sector should be significant as a result of free trade-related restructuring.

It is assumed that growth in Manitoba will be spurred by construction of utilities projects as the Nelson River's hydroelectric potential is developed. Alberta will reap some economic growth benefits from diversification efforts, with added production capacity in food processing, chemicals and wood products. Growth in Saskatchewan will continue to hinge on international demand for its commodities, including grain, potash, uranium, oil and gas.

Given the size of its forestry and wood products sectors, British Columbia's economy is largely dependent on North American demand for housing. This demand is assumed to decline in the short term but pick up again for the remainder of the century. There should be strong productivity gains in these sectors, as well as in metal mining and some goods-producing sectors.

5. Alternative Case

As previously indicated, the alternative case (table 4.2) incorporates a lower oil price scenario and economic growth that is 15 per cent greater, cumulatively, than that of the reference case (i.e., 2.7 percent instead of 2.4 percent over the forecast period). This is a relatively faster rate of growth than would normally be expected from such an oil price scenario. It is being used to develop an energy demand forecast which is sufficiently different from the reference case. The two well-differentiated cases will provide alternative and useful demand outlooks against which energy and environmental analyses can be performed.

In the alternative case, the faster rate of economic growth is assumed to result from a sudden burst of investor and/or consumer confidence. This increases the level of consumer expenditures and, particularly, investment expenditures -- both domestic and foreign. Along with increased growth in the Gross National Product (GNP), both employment and productivity rise, the latter as a result of increased investment in technological equipment. Improved employment prospects lead to slight increases in the participation rate and immigration. It is further assumed that, despite faster growth, prices and interest rates remain at a level associated with a strictly low-price case: lower costs as a result of higher labour productivity (and lower oil prices) offset the effects of demand-pull inflation.

Table 4.2

MAIN MACROECONOMIC ASSUMPTIONS - ALTERNATIVE CASE

(CANADA)
(Average Annual Growth Rates)

	1988-95	1995-00	2000-05	2005-20	1988-20
Real GDP	2.6	2.8	2.9	2.6	2.7
Industrial RDP	2.9	3.5	3.6	3.2	3.2
Services RDP	2.3	2.5	2.5	1.9	2.2
CPI	3.6	3.8	4.3	4.0	3.9
US WPI	3.4	3.8	4.2	4.0	3.9
Employment	1.3	1.4	1.6	1.1	1.2
Total Population	1.2	1.0	0.9	0.6	0.9
Total Households	1.6	1.4	1.5	1.5	1.5
Labour Force	1.1	1.0	1.0	1.0	1.0

6. Risks, Uncertainties and Caveats

Although the assumptions described above are those most likely to unfold, unpredictable events or disruptions could alter our reference case forecast. For example, U.S. monetary policy could tighten further over the next few years, and could even be exacerbated by strict fiscal restraint, given the obvious and urgent need to reduce that country's budgetary deficit. There could be greater than anticipated liberalization of international trade as a result of European integration, the multinational trade negotiations and the opening-up of Soviet bloc countries and Asian centralized economies. It should also be noted at this point that the new Goods and Services Tax scheduled for 1991 is not included in our assumptions, as it is currently before Parliament.

Despite the growing importance of environmental issues and the increasingly urgent need to develop energy-saving solutions, policies and programs dealing with environmental objectives are included to only a limited extent.

V. ENERGY DEMAND

1. Introduction

The energy price increases of the 1970s and early 1980s led to two major changes in the pattern of energy use in Canada: a marked decrease in energy-use intensity[4] and a substitution away from oil in favour of less costly fuels (electricity and natural gas). The combination of higher energy prices and government off-oil programs resulted in a pronounced reduction in energy-use intensity (down by an annual average rate of 1.5 per cent between 1972 and 1988). Simultaneously, oil's share of total energy consumption decreased from 49 per cent in 1978 to about 40 per cent in 1988. Meanwhile, the share of other energy sources increased, with electricity recording the biggest jump (from 16 per cent in 1978 to 23 per cent in 1988). These dual trends -- a reduction in energy-use intensity and a switch to non-oil energy source -- are observed in all the sectors of the economy (table 5.1).

For the most part, these changes have worked their way through and new patterns of energy use are now in place. With the help of the updated version of EMR's IFSD model (a description of the model is available upon request), an attempt has been made to analyze these trends over the forecast period. It is expected that the decline in energy-use intensity will abate considerably in the near term. The shift away from oil is expected to continue in all sectors (except transportation), but at a reduced pace. Strict environmental measures, however, would likely change this pattern. Outside of the transportation sector, electricity will increasingly become the dominant fuel. In terms of sectoral breakdown, energy consumption will grow fastest in the industrial sector (chart 5.1).

Table 5.1

SECONDARY ENERGY INTENSITY TRENDS
(Average Annual Growth Rates)
By Sector

	Historical		Reference Forecast	
	1962-72	1972-88	1988-05	2005-20
Secondary demand per RDP	0.30	-1.50	-0.5	-0.2
Residential demand per Household	1.10	-2.50	-0.50	-0.20
Commercial demand per Commercial RDP	5.50	-3.30	0.30	0.00
Industrial demand per Industrial RDP	-0.20	0.10	-0.20	-0.10

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[4] Secondary energy consumption divided by total RDP.

2. Sectoral Demand

The following is a brief sectoral analysis of energy demand in the reference case.

Residential Sector

In examining energy conservation in the residential sector, it is important to look closely at trends in the housing market. A breakdown of the market in terms of existing houses and new dwellings and the proportion of single to multiple units in the total housing stock play key roles in determining energy conservation in the residential sector. In existing houses, conservation stems mainly from upgrading insulation and replacing inefficient heating/cooling systems. Since the mid 1970s, there has been a significant increase in conservation measures on existing houses due to sharp energy price increases and attractive government incentives. By the same token, new houses have become more fuel-efficient as a result of more stringent construction standards and consumer awareness of potential savings on fuel bills. The shift from single housing to multiple and row housing has also contributed to reduced energy consumption, as multiple housing units are more sheltered from the elements than single units.

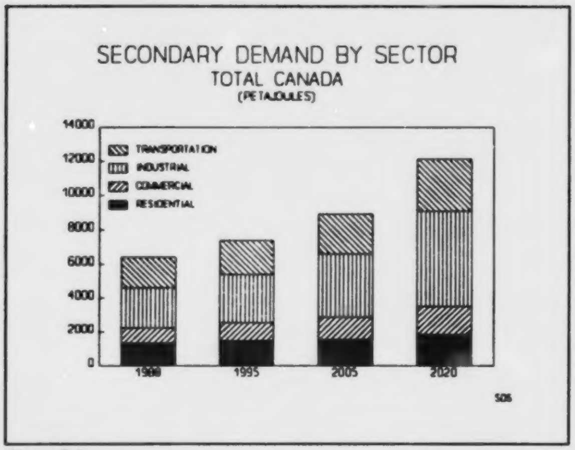

Chart 5.1

It should be noted that the model estimation indicated that the residential sector was more price-sensitive than other sectors. As shown in table 5.2, one would not expect the trend in energy conservation of the last 15 years to continue for three reasons:

- energy prices are not expected to return to their historical highs;
- the current housing stock is much more energy efficient; and
- no government incentives are assumed in this outlook. It should be noted, however, that Ontario Hydro recently announced a major demand management program. Other electrical utilities may develop similar programs.

Table 5.2

RESIDENTIAL DEMAND AND KEY DETERMINANTS
Reference Case
(Average Annual Growth Rates)

	1988-95	1995-05	2005-20
Residential Real Energy Prices	0.1	1.1	-0.3
Residential Energy Demand	1.4	0.6	1.1
Households	1.5	1.3	1.3
Residential Demand per Household	-0.1	-0.7	-0.2
Real Disposable Income per Capita	0.8	1.2	1.3

Growth in residential energy demand varies considerably from region to region. This is due chiefly to different growth in household formation and, to a lesser extent, to different heating fuel compositions (chart 5.2). The latter stems from the fact that, in those provinces which are heavily dependent on electricity for heating purposes, households will tend to be less energy-efficient (i.e. they will consume more energy) because electricity prices are expected to rise less rapidly than oil and gas prices.

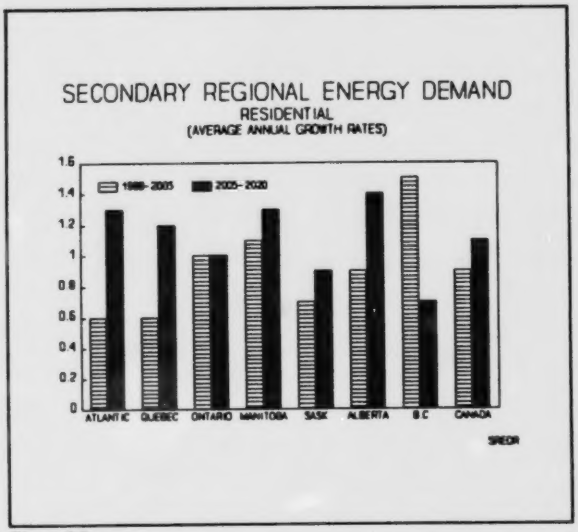

Chart 5.2

With slower population growth, Quebec's relative contribution to total residential energy demand is projected to decline over the forecast period. Residential energy demand is projected to rise more rapidly in Alberta and British Columbia, relative to the national average, because of stronger household formation growth. In fact, our projections show that Alberta's contribution to total growth will exceed that of Quebec over the 2005-2020 period.

The breakdown of total energy demand by fuel is essentially based on relative fuel prices and, to a lesser extent, on the availability of natural gas, particularly in British Columbia (Vancouver Island Pipeline). As discussed in Chapter III, electricity prices are projected to rise less rapidly than oil and natural gas prices. For Canada as a whole, the ratios of residential electricity to oil and natural gas prices is projected to decline by approximately 22 to 25 per cent by 2020. It should be noted that the relative price shifts occur primarily between 1988 and 2005. In line with these relative price changes, projections call for electricity to increase its share of the market at the expense of both oil and gas, particularly in the Atlantic, Quebec and Manitoba. While relative price shifts stabilize by 2005, the adjustment process is expected to continue because of the long lag effects of prices on fuel substitution (see chart 5.3 for residential market shares).

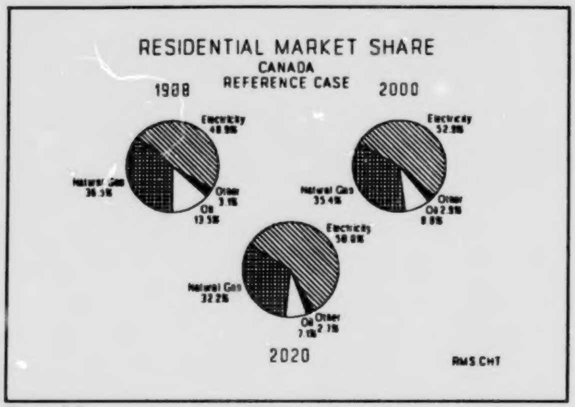

Chart 5.3

Commercial Sector

Energy uses in the commercial (and public administration) sector are similar to those in the residential sector: heating and cooling buildings, lighting, etc. Therefore, the same influencing factors are at play. These include generally slower economic growth than in the past as well as slower population growth -- both of which imply a slowdown in commercial construction activity. Electricity is projected to increase its share of the market over the forecast period, chiefly at the expense of natural gas (chart 5.5).

In the reference case, growth in commercial energy demand drops from an annual rate of close to four per cent in the late 1980s to approximately 2.5 percent through to the mid-1990s. It continues to fall steadily over the forecast period to average about 1.7 percent between 2005 and 2020. Beyond 2005, although price growth slackens, other factors (such as demographics) continue to restrain demand (table 5.3)

Table 5.3

COMMERCIAL DEMAND & KEY DETERMINANTS
Reference Case
(Average Annual Growth Rates)

	1988-1995	1995-2005	2005-2020
Commercial Real Energy Price	-0.7	0.9	-0.4
Commercial Energy Demand	2.9	2.3	1.7
Commercial RDP	2.1	2.1	1.7
Commercial Demand/RDP	0.6	0.1	0.0

Most provinces follow the national trend of diminishing growth in commercial energy demand (chart 5.4). The only exception is Saskatchewan, where the growth rate is below one per cent between 1988 and 1995, and then hovers steadily at just above the one per cent mark for the remainder of the forecast period. This reflects a softness in employment and household creation in Saskatchewan, and therefore of service sector growth (this includes housing starts, education and health).

Fuel market-shares for the commercial sector are projected to change in favour of electricity over the forecast period (chart 5.5). In fact, electricity is projected to increase its share of the market by about 10 percentage points, chiefly at the expense of natural gas.

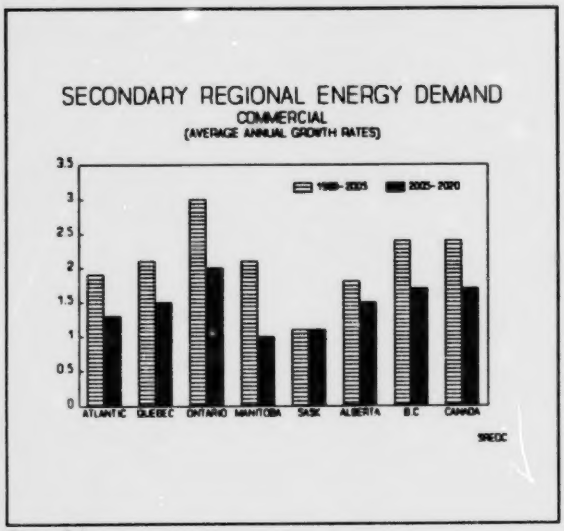

Chart 5.4

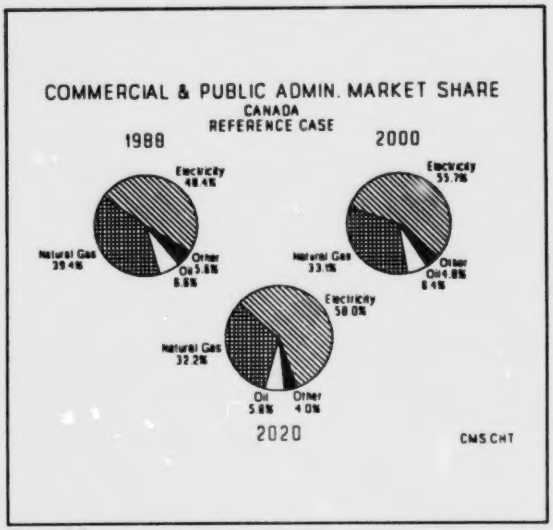

Chart 5.5

Industrial Sector

The industrial sector experienced a decrease in energy-use intensity during the 1972-1988 period that is considerably less than that experienced by other economic sectors. This is because energy substitution and/or energy-use improvement are not as straightforward in the industrial sector as in the other sectors. Energy is very often an essential input in the industrial sector and, thus, is difficult to substitute. Furthermore, a reduction in energy consumption may require an increase in the consumption of other inputs.

Corporate investment strategies are often long term and focus on enhancing product quality, increasing market shares and reducing total costs. In fact, investment decisions depend on many non-cost factors such as general economic conditions, competitiveness, government policies, the cost of borrowing money, the economic health of a particular industry, etc.

Since an objective of any firm is to cut total production costs, there would be no guarantee that energy consumption would be reduced given the inherent uncertainties of new technologies. However, the most recent data show that between 1983 and 1988 the industrial sector reduced its energy-use intensity by 5.7 per cent. It should be noted that this was a period of increasing labour productivity and capacity utilization. Thus, the significant decline in intensity in recent years is not an indicator of future trends.

Unlike the residential and commercial sectors, aggregate measures of industrial intensity are difficult to interpret because the net energy efficiency calculations exclude the effects of changes in the industrial structure[5] and increased energy requirements due to environmental considerations. The industrial demand projections presented in this chapter are essentially based on price-induced conservation and technological improvements incorporated into energy-using equipment in the 1980s and during the forecast period. Since environmental objectives and targets are currently being defined, a continuation of current environmental standards is assumed.

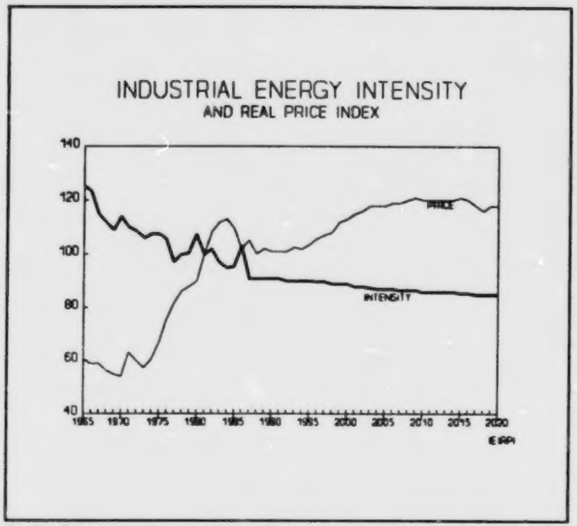

Chart 5.6

Table 5.4

INDUSTRIAL DEMAND & KEY DETERMINANTS

Reference Case
(Average Annual Growth Rates)

	1988-1995	1995-2005	2005-2020
Industrial Real Energy Prices	0.2	1.4	-0.1
Industrial Energy Demand	2.4	2.7	2.7
Industrial RDP	2.5	3.0	2.8
Industrial Demand/RDP	-0.1	-0.3	-0.1

---

[5] Energy consumption is concentrated in a limited number of relatively small industries. For example, the mining, pulp and paper, iron and steel, cement, chemicals and smelting and refining industries account for approximately 75 per cent of total industrial energy consumption while their share in total industrial production is only about 25 per cent.

Our projection calls for only minor shifts over the next 30 years in the regional composition of industrial energy demand, reflecting our macro-economic scenario that provincial economic trends will generally follow the national trend (chart 5.7). Central Canada will continue to account for the lion's share of industrial energy demand. However, as of 2005, the rate of growth of Central Canadian industrial energy demand will stagnate or slow down, whereas that of most western provinces will accelerate after almost 20 years of comparative sluggishness (due to such factors as slower growth in the forestry and wood products industries in B.C. which in turn is caused by slower growth in the North American housing market).

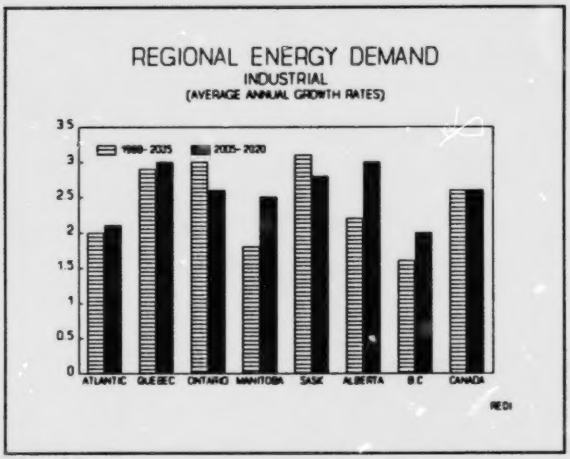

Chart 5.7

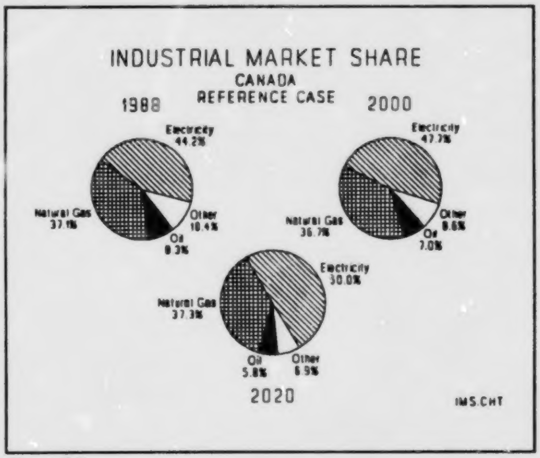

Chart 5.8

Historically, the industrial sector has been quite responsive in substituting fuels as a result of relative price changes. Since 1970, electricity and natural gas have made significant gains at the expense of heavy fuel oil. It should be noted that the recent strong increase in electricity demand is somewhat misleading because it is due in part to Hydro Quebec's program of selling surpluses to major industrial users at advantageous rates. This program was terminated in 1988. Based on relative price shifts, our projection shows that the share of electricity will continue to increase (but at a more moderate pace), mainly at the expense of heavy fuel oil. Natural gas is expected to maintain its current share of the market.

Transportation Sector

In 1988, the transportation sector accounted for about 28 per cent of total secondary energy demand and about 69 per cent of total refined petroleum products demand. Road transport was the largest component at about 83 per cent, up from 74 per cent in the early 1960s. Within the road sector, motor gasoline is the dominant fuel, accounting for 77 per cent of total demand, followed by diesel at 21 per cent.

Following a period of rapid growth (seven per cent per year) in the 1960s and early 1970s -- which resulted from strong economic growth and declining energy prices -- demand for motor gasoline grew by only three per cent per year between 1973 and 1980 and declined by five per cent per year between 1980 and 1987. Initially, this was in response to much higher energy prices, and subsequently to the economic recession of the 1980s. More recently, motor gasoline demand has been increasing at one per cent per year, as the purchase of bigger vehicles has resulted in some deterioration in the fuel efficiency of the average new car. However, average fuel efficiency of the total car fleet continued to improve at about three per cent per year as the vehicle stock turned over, reflecting the technological improvements made during the period of increasing oil prices. These improvements and lower energy prices have continued to reduce the gasoline cost of driving by about six per cent per year. As a result, during this period, the average distance travelled per car increased by about 1.5 per cent per year. At the same time, in response to more rapid increases in income and lower motor gasoline prices, new car sales increased significantly, resulting in car stock growth of over two per cent per year.

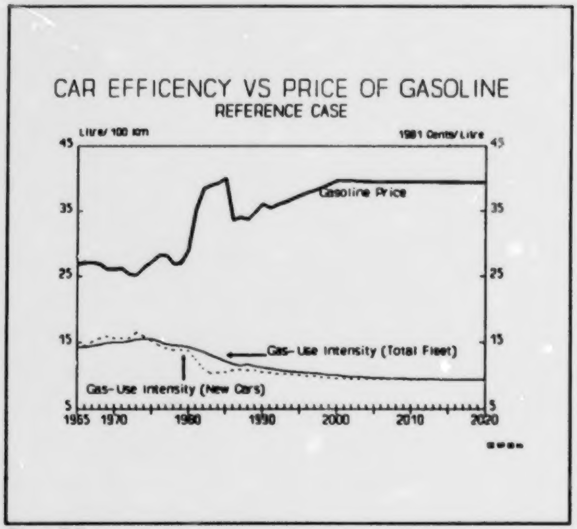

Chart 5.9

Our forecast captures the process of the gradual turnover of the car stock and its effects on gasoline demand. The key question is how the small increases in gasoline prices over the medium term, and essentially flat prices in the long term will affect the fuel efficiency of the average newly purchased car. The view in this outlook is that the sharp improvements in new car efficiency that resulted from expectations of much higher prices combined with weak real incomes are not sustainable. A modest improvement of 13 per cent in the fuel efficiency of new cars is projected over the entire forecast period. In the medium term, new car efficiency improvements are expected to result from increases in motor gasoline prices. After 2000, when motor gasoline prices are essentially flat, some improvements are expected to continue as a result of competition between manufacturers to provide technologically superior and cost-effective automobiles. However, such factors as consumer preference for light trucks and vans and options that require the use of more power (e.g. air-conditioning) may prevent large efficiency gains comparable to those achieved in the early 1980s. (Chart 5.9 shows the relationship between gasoline prices and automobile gas-use intensity, i.e. gasoline consumption for a given distance of travel).

Total motor gasoline demand is projected to increase by 1.3 per cent per year (table 5.5). Demand for road diesel increases at a more rapid rate of 2.3 per cent. As a result, the share of diesel in road transport is expected to increase from its current 23 per cent to 29 per cent by 2020. Several alternative fuels (propane, compressed natural gas, ethanol and methanol) are now being used in Canada. A small increase in the proportion of these fuels is assumed. The share of compressed natural gas (CNG) and propane in the road sector is projected to increase from the current 2 per cent to 2.5 per cent in the reference case, but remain unchanged in the alternative case. It is worth noting that factors other than energy costs could lead to increased use of alternative fuels. In particular, environmental concerns (e.g. lead phase-out and restrictions on vehicle emissions) could lead to significant acceleration in the rate of growth of alternatives to gasoline and diesel. This sector would be a target for policies in Canada and the U.S. which could accelerate efficiency gains.

Table 5.5

MOTOR GASOLINE DEMAND: KEY COMPONENTS

Reference Case
(Average Annual Growth Rates)

	1984-1988	1988-1995	1995-2005	2005-2020
Motor Gasoline Demand	1.0	0.7	1.2	1.6
Car Stock	2.5	1.8	1.8	1.7
Stock Efficiency	-3.0	-1.4	-0.9	-0.2
Average km. driven per car	1.5	0.2	0.2	0.1

In the air transport sector, energy demand is expected to grow by two per cent over the forecast period. This is a drop from the recent rate of 4.5 per cent, reflecting the increased fuel efficiency of newer aircraft and more stable growth in air travel after a recent recovery. Marine and rail each currently account for about five per cent of transportation energy demand. Rail sector energy demand is projected to grow at 2.8 per cent; the corresponding growth rate for the marine sector is 2.0 per cent.

Feedstocks

The increase in Alberta's use of feedstock material is the dominant factor for the natural gas liquids (NGLs) component of the non-energy forecast, because of the large increase in ethane use. Ethane accounts for about 95 per cent of the Alberta NGL non-energy total. Outside of Alberta, use of NGLs as a feedstock is forecast to rise from 40.3 PJ in 1988 to 89 PJ in 2020. Oil-based petrochemical feedstocks are forecast to increase much more slowly, with total growth of only about 50 per cent in the next 30 years, from 125 PJ in 1988 to 196 PJ in 2020. These increases are related largely to economic growth.

The largest change for NGLs from the previous forecast is the inclusion of ethane mixes in enhanced oil recovery (EOR) requirements. The estimates of propane and butane mixes for EOR requirements have also been included.

3. Fuels Demand

The results of our reference case scenario show that by the year 2005 Canadians will consume 40 per cent more energy than in 1988, and that, by 2020, they will consume 90 per cent more. Although most of the increase in energy consumption would be from electrical sources, the consumption of oil in 2020 would be 66 per cent above its level for 1988.

Since increases in oil prices are higher than those for alternative fuels, its share of total secondary demand falls from 40 per cent in 1988 to 35 per cent in 2020. However, oil still remains the principal energy source in Canada. Electricity's share increases from 23 per cent in 1988 to 30 per cent in 2020, as its price competitiveness improves. Demand for natural gas will increase by 2.1 percent per year, in line with growth in total energy demand. Therefore its share remains constant (at about 25 percent).

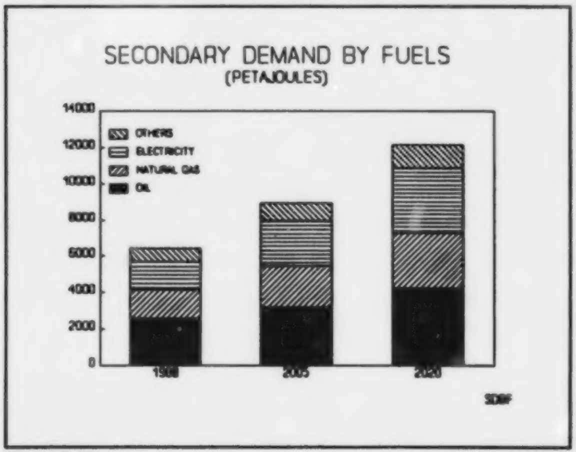

Chart 5.10

As the demand for electricity increases, hydro sources will become more and more scarce. Therefore, it is projected that electricity supplies will increasingly come from other sources, such as nuclear stations. Our reference case forecast shows that nuclear electricity production increases by an annual average rate of 4.3 per cent between 1988 and 2020, compared to only 2.2 per cent for hydro electricity. (For further details see chapter VIII).

4. Alternative Scenario

The energy demand projection for the alternative scenario was developed in two steps. Firstly, the energy demand implication of the low world oil price scenario (see chapter II) was projected for a consistent set of prices of alternative fuels and rate of economic growth. It is interesting that secondary energy demand in this low price scenario is only about 5 per cent higher than in the reference case by 2020 whereas the gap in oil prices is of 20 per cent. The reason for this is that, after 1995, natural gas and electricity prices are relatively insensitive to oil price movements due to tight markets. Thus, while crude prices are projected to be 20 per cent lower than in the reference case by 2020, natural gas prices are only 11 per cent and electricity prices are about five per cent lower. It can therefore be concluded that Canadian energy demand is not likely to respond, in any major way to the kind of world oil price changes analyzed in this forecast.

In the second step, a macroeconomic growth rate that is higher than one would expect was superimposed onto the low oil price scenario. In other words, GDP growth over the entire forecast period was set at 15 per cent above that of the reference case. This approach was adopted in order to adequately differentiate demand projections in the two cases.

Table 5.6

ALTERNATIVE SCENARIO
(Percentage Difference from Reference Case)

	Price Effect			Price & Income Effect		
	1995	2005	2020	1995	2005	2020
RDP	0.9	0.8	0.8	1.8	5.6	11.1
Household	0.0	0.0	0.0	0.8	2.3	4.7
CPI	-2.1	-2.5	-2.5	-2.1	-2.5	-2.5
Secondary Demand:						
Total	2.9	5.3	4.8	3.6	8.7	13.3
Residential	2.7	6.8	7.1	2.9	7.5	9.5
Commercial	1.0	1.5	1.4	1.7	5.2	9.1
Industrial	2.1	3.5	3.5	3.0	8.1	14.1
Transportation	5.3	9.0	7.8	6.0	12.5	16.4
By Fuel:						
RPP's	7.7	11.7	10.9	8.4	15.6	20.2
Natural Gas	-0.2	2.2	0.3	1.1	8.3	13.6
Electricity	0.3	1.6	3.0	0.0	3.1	7.6
Coal	2.5	4.1	3.7	3.3	8.9	14.9

Thus, total secondary energy demand by the year 2020 is 13.3 per cent higher in the alternative case than in the reference case. Energy consumption is up in all sectors, but more so in those that are most dependent on oil, such as the transportation and industrial sectors. It can be seen that, whereas prices are a more significant factor than economic activity in the residential sector, the opposite is true in the commercial, industrial and transportation sectors.

Given its basic independence from oil prices, the relative price of electricity is higher in the alternative case than under the reference case. The projected increase in electricity consumption is therefore not as high as for other fuels. The overall conclusion is that in the 1990s, Canadian energy demand is likely to be more responsive to the level of economic activity than to oil prices, with the possible exception of refined petroleum products.

5. Conclusion

The results of our alternative (low price, high growth) scenario confirm the sensitivity of energy demand to economic growth. Indeed, with a rate of economic growth that is greater than normal from an energy price effect, we find that secondary energy demand increases by an annual average rate of 2.4 per cent (compared to 2 per cent under the reference case) between 1988 and 2020. In 2020, energy demand is 13.3 per cent higher relative to the reference case and oil demand is 20.2 per cent higher. In the absence of major policy and program changes, we see limited improvements in energy efficiency and moderate substitution between fuels.

VI. OIL SUPPLY AND TRADE

1. Introduction

In developing the oil supply forecasts for this outlook, consideration was given to available information on geology, engineering and the economic aspects of various sources of supply, consistent with the forecasting framework. Consultation with experts from within and outside EMR was also important in developing the supply projections. The Oil and Gas Supply Impact Model (OGSIM), a modelling framework which relates industry cashflow to investment and ultimately reserve additions, was used to ensure that projected supply can be achieved with the funds available to the industry for investment.

Since our last Energy Outlook (1988), both National Energy Board (NEB) and the Energy Resources Conservation Board (ERCB) have published supply forecasts which are higher than their previous forecasts, reflecting more optimistic views on resource potential. In reviewing our own methodology, it was found that there had been a tendency to overestimate non-conventional supply and underestimate conventional light oil supply[6]. Total projected oil supply, however, did not vary significantly from actual supply. It was also found that the difference in types of production could be explained by economic factors such as netbacks.

An extensive review was also carried out of recent developments in oil and gas supply modelling to determine which aspects could be incorporated into our supply framework. A number of studies recognized that industry cashflow was important in determining industry activity, but did not suggest what would be considered an appropriate reinvestment ratio. As in OGSIM, some studies explicitly linked the level of investment and reserve costs to reserve additions and thus supply. The studies reviewed, however, had problems in estimating costs, drilling activity, oil and gas intentions, reserve additions, profitability and production. The studies also focused on conventional supplies and did not develop a framework for estimating supplies from non-conventional sources including bitumen and frontier production. For these projections, the views of EMR's Projects Groups were sought with regard to start-up dates and project costs.

Crude prices for Canadian producers under the reference and alternative cases are summarized in table 6.1. In addition to oil prices, other assumptions -- such as the level of reinvestment of industry cashflow, the ratio of oil/gas expenditures, reserve costs and development of major projects -- are key to the oil and gas supply projections. These assumptions are summarized in appendix A.

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[6] C.J. Seeto and A.J. Persaud, "Comparison of NEP and Current Oil Supply Projections", Economic & Financial Analysis Branch, EMR, June 1988.

Table 6.1

PAR CRUDE PRICES AT EDMONTON*
(C$1989 / bbl)

	Reference Case	Alternative Case
1988	19.40	19.40
1995	26.05	19.90
2005	30.60	24.85
2020	30.75	25.00

* Based on an exchange rate of 0.80 US$/C$.

2. Crude Oil Supply

Crude oil production in Canada increased to 1720 mb/d in 1988, 4.6 per cent above 1987 levels, surpassing the highest levels attained since 1974. This increase occurred despite the oil price collapse of 1986 and continued uncertainty in world crude markets over the past two years. This trend of increasing oil production has continued unabated since 1982. Increased oil production in 1988 resulted from growth in all sources of supply. The principal factors for the increase include drilling incentives, lower production and operating costs, expansion of the Interprovincial Pipeline System (IPL), the modified pro-rationing plan in Alberta and Syncrude's recently completed Capacity Addition Program (CAP).

Under both price scenarios, conventional reserve additions are projected to decline from levels attained in the last five years (table 6.2). In the short to medium term, the pace of reserve additions is constrained by lower industry cashflow, higher directed gas drilling activity and competition for funds for non-conventional investments. In the long term, higher finding and development costs due to limited resource potential also result in declines in reserve additions. Total reserve additions under the reference case are 15 per cent higher than in the alternative case.

Total oil reserve additions under this year's projections are higher than in last year's projections, due in part to lower finding and development costs. The increase in reserves is not inconsistent with ERCB's recent comprehensive analyses which show significant upward revisions of oil potential in Alberta (table 6.3).

Table 6.2

CONVENTIONAL CRUDE OIL RESERVE ADDITIONS*

(millions of barrels per year)

	Light Oil		Heavy Oil	
	Reference Case	Alternative Case	Reference Case	Alternative Case
Annual Averages				
1988-1997	220	194	68	58
1998-2007	170	145	82	68
2008-2017	125	105	65	61
2018-2020	105	100	62	59
TOTAL (1988-2020)	5465	4740	2336	2047

* Includes Enhanced Oil Recovery but does not include reserves associated with megaprojects.

Table 6.3

ALBERTA ULTIMATE OIL POTENTIAL

(billions of barrels)

	ERCB REPORT 85-A	ERCB CURRENT	% CHANGE
Light Medium	15.29	16.33	+6.8
Heavy	1.39	1.95	+40.3
Pentanes Plus	2.01	2.70	+34.3
Bitumen	44.05	62.93	+42.9
Synthetic Crude Oil	245.43	245.43	0
Total	308.17	329.34	+6.9

Source: ERCB Report 88-E, December, 1988

In the reference case, total crude oil supply increases slightly to 1750 mb/d in 1991 before declining slowly to a low of 1630 mb/d in 1997. It then increases to about 2000 mb/d by 2003 and remains around this level for the rest of the forecast period (chart 6.1 and table 6.4). In the alternative scenario, total oil supply remains relatively flat until 1990, before declining to a low of a volume 1400 mb/d in 1998. Oil supply then increases gradually to 1560 mb/d by 2012 and remains at around this level for the rest of the forecast period (chart 6.2 and table 6.4). In 2020, oil supply is 15 per cent higher than the current level of production in the reference case and 10 per cent lower in the alternative case.

Declining production in the medium term reflects the decline in conventional established reserves and reserve additions. In the long term, as oil prices climb, the increase in production results from continued development of bitumen projects and of high-cost production from synthetic plants and the frontiers. The long term elasticity implied in these projections is about unity. This relatively high elasticity is a consequence of the nature of the Canadian resource base, with significant resources available in the US$20-to-$25/bbl range.

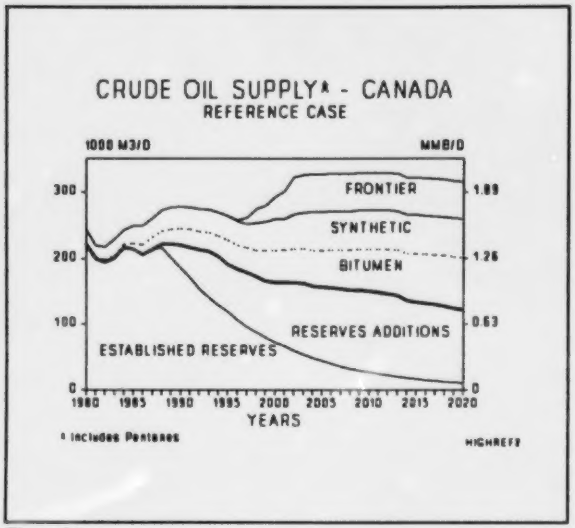

Chart 6.1

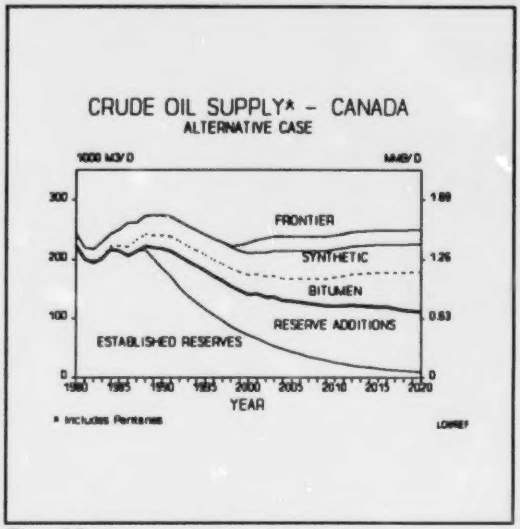

Chart 6.2

Conventional Light & Heavy Crude Oil

Conventional light crude oil supply (including pentanes) is projected to decline at an annual average rate of two per cent in the reference case (from 1106 mb/d in 1988 to 586 mb/d in 2020), and at an annual average rate of 2.2 per cent in the alternative case (to 534 mb/d).

Conventional heavy crude oil supply is expected to decline more gradually. Under both price scenarios, heavy oil supply is not expected to fall below its 1988 level until 1993. The less rapid decline in total heavy oil supply is due mainly to increased production from Alberta.

Table 6.4

OIL SUPPLY FORECAST

(thousands of barrels per day)

Reference Case

	Conventional		Synthetic	Bitumen	Offshore(2)	Total
	Light(1)	Heavy				
1988	1106	285	200	130	-	1721
1989	1100	302	211	136	-	1749
1992	1050	294	211	175	-	1730
2005	752	235	367	352	351	2057
2010	734	215	367	406	351	2073
2020	586	181	367	503	351	1988

Alternative Case

	Light(1)	Heavy	Synthetic	Bitumen	Offshore(2)	Total
1988	1106	285	200	130	-	1721
1989	1090	297	211	127	-	1725
1992	1005	286	211	159	-	1661
2005	630	182	298	243	151	1504
2010	586	173	298	308	151	1516
2020	534	162	298	428	151	1573

(1) Includes Pentanes
(2) Excludes Norman Wells which is included in conventional light

Oil Sands - Synthetic Oil

The oil sands resource base of over 300 billion barrels represents the largest source of potential oil supply in Canada. Potentially recoverable oil sands reserves comprise about 40 per cent of total established world oil reserves. The principal methods of extracting oil sands are surface mining and in-situ recovery.

For the purpose of this forecast, under the reference case, two new integrated mining plants with a capacity of 70 mb/d are projected for start-up in the late 1990s and early 2000s. In the alternative case, only one plant is assumed, with production commencing in the early 2000s. In addition, a minor tar sands expansion of 20 mb/d is projected for start-up in 1993 in the reference case and 1995 in the alternative case. New stand-alone facilities require relatively long lead-times of at least five years to plan and build. In an environment of volatile oil prices, private project sponsors may need the commitment of governments to reduce or share the risks of these projects.

Over the last few years, producers at existing synthetic plants have succeeded in cutting operating costs in half -- from the US$30/bbl range in the early 1980s to US$15/bbl at present. Efforts to reduce costs are continuing, and sponsors of the proposed OSLO project are hoping to reduce the costs of their project to around US$10/bbl. Under the reference case, operating costs are assumed at US$15/bbl, and under the alternative case at US$12/bbl.

In 1988, Suncor and Syncrude, Canada's two integrated surface mining and upgrading facilities, accounted for all of the synthetic oil production of 200 mb/d (12 per cent of total oil production). Under both price scenarios, the share of synthetic production is expected to be higher by the end of the forecast period.

Oil Sands - Bitumen

Bitumen supply has increased rapidly from 25 mb/d in 1983 to 130 mb/d in 1988. Under the reference scenario, bitumen supply is projected to increase continuously to around 500 mb/d by 2020. Under the alternative scenario, bitumen supply is projected to decline slightly in 1989 before increasing continuously to reach around 425 mb/d in 2020.

The increase in bitumen supply is expected to result from expansions of projects in the Cold Lake, Wolf Lake and Peace River areas. In the short run, however, the postponement of several of these major development projects (due to low oil prices) will result in much slower growth in bitumen supply. Operating costs for bitumen are assumed to be in the range of $6-$8/bbl ($1989) and supply price is assumed to be in the range of $10 -$15/bbl.

Frontiers

Canada's frontier regions, which are known to contain vast resource potential, are relatively unexplored. Of the estimated 24 billion barrels of oil potential, only around 16 per cent is considered to be discovered resources. Major discoveries have been made at Hibernia (offshore Newfoundland) and Amauligak in the Beaufort Sea. Smaller accumulations have been found in the vicinity of these discoveries, as well as offshore Nova Scotia, in the Arctic

Islands and the Mackenzie Delta. In 1988, delineation programs continued at the Terra Nova and Whiterose oil discoveries off the east coast, as well as Amauligak. An Agreement in Principle to develop Hibernia was also signed last year.

In the reference scenario, frontier production is expected to commence in 1996 from Hibernia and in 1999 from a Terra Nova-like project, followed by production in 2000 from the Beaufort Sea. Under the alternative scenario, production from the east coast is assumed to be delayed for two years and no production is assumed from the northern frontiers.

Although there has been demonstration production only from Bent Horn in the Arctic and Amauligak in the Beaufort Sea, production from the frontier is projected to play an important role in Canada's future oil supply. In the reference scenario, frontier supply is projected to increase from 12 mb/d in 1996 and peak at 350 mb/d in 2002, where it will remain at this level until 2020. In the alternative scenario, frontier oil supply is projected to increase from 12 mb/d in 1998 and peak at 150 mb/d in 2001, where it will remain until 2020. (It should be stressed that these assumptions were developed for the purposes of our two scenarios only.)

3. Heavy Oil Markets

Heavy oil can be upgraded to light oil in stand-alone upgrading facilities or it can be processed at specially adapted refineries. At present, only a small amount of the heavy oil produced in Canada can be processed in Canadian refineries. The domestic demand for heavy crude oil is currently about 110 mb/d. The commencement of operation of the Newgrade upgrader in 1989, and the expected start-up of the Lloydminster upgrader in 1993, will add a total of 100 mb/d to the otherwise modest growth in Canadian heavy oil demand. Large surpluses of Canadian heavy oil, however, would still be available for export under both scenarios, as domestic demand is expected to be well below projected supply (charts 6.3 and 6.4).

Canadian heavy oil exports to the U.S. Northern Tier are currently around 350 mb/d. With further displacement of Mexican imports, declining Wyoming Sour supply and the addition of new upgrading facilities, market potential in the U.S. Northern Tier is estimated to be in the range of 450 to 500 mb/d. In the reference scenario, producers would therefore have to look for new markets beyond the U.S. Northern Tier in order to sell all their production after 2010. Under the alternative scenario, additional markets in the U.S. Northern Tier should be able to absorb all the available heavy oil exports.

Producers are already exploring new markets. Those considered to have good potential include the Wood River market (southern Illinois), the Pacific Rim and the U.S. east coast. As prices in the reference case are expected to be much higher than current levels, producers should be able to absorb the negative impact on netbacks that will result from exporting to these new markets.

A possible constraint on increased heavy crude oil supply, especially bitumen, is the availability of diluent. However, this problem is not as severe as previously anticipated, due to increased pentanes supply (resulting from higher gas production), the discovery of the Caroline gas pool and the projected supply of 20 mb/d of condensate from the Northern frontiers. Given that producers are already investigating and implementing short term solutions, diluent availability should not be a problem until the early to mid-1990s. Longer term solutions being investigated by producers include diluent recycling from the U.S. Northern Tier, oil in water emulsions and the building of partial field upgraders.

4. Oil Trade

Under the reference Case, Canada is expected to remain a net oil exporter until 2010 (except for 1996 and 1997, when small imports are required). Net imports are then projected to grow to 470 mb/d (or 20 per cent of demand) by 2020. Under the alternative case, Canada is expected to be a net importer much earlier: in 1993. Net imports are also projected to be significantly higher in 2020, at 1330 mb/d (or 45 per cent of total demand). Canada's reliance on light imports, which is somewhat masked by the export of surplus heavy oil, is expected to increase over the forecast period. Light oil imports are projected to increase from around 90 mb/d in 1988 to 1045 mb/d and 1740 mb/d in 2020 under the reference and alternative scenarios respectively.

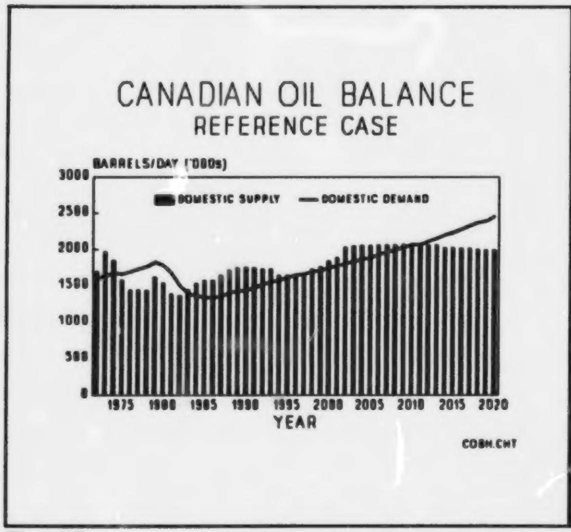

Chart 6.3

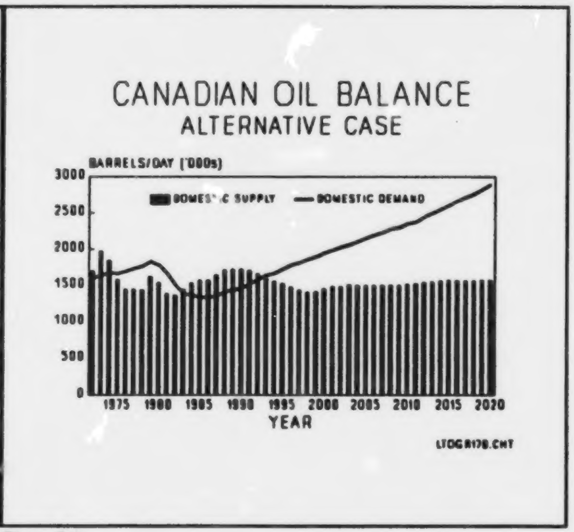

Chart 6.4

5. Oil and Gas Investments

In developing the oil and gas outlook, it was assumed that the industry reinvests 80 per cent of its internal cashflow, lagged one year, until 2000 under the reference case and until 2005 in the alternative scenario. For the rest of the forecast period, the reinvestment ratio is 75 per cent, lagged one year. The corresponding ratios based on the current year cashflow average 74 per cent and 72 per cent respectively. The one year lag reflects the assumption that industry spending plans are developed on the basis of the previous year's cashflow. The slight decline in reinvestment ratios in the long term is based on the assumption that, with increasing costs and stable prices, industry might direct expenditures towards better investment opportunities in other industries and/or countries.

In the reference case, 60 per cent of industry expenditures are assumed to be directed towards oil activity and the remaining 40 per cent towards gas activity. Under the alternative case, oil's share of expenditures is 55 per cent, with 45 per cent of expenditures directed to gas activity.

Table 6.5

GROSS OIL AND GAS UPSTREAM INVESTMENT

Annual Average
(Billions of C$1989)

	Reference Case	Alternative Case
1988-1997	8.3	5.6
1998-2007	11.5	7.9
2008-2017	11.5	9.4
2018-2020	11.5	9.4

Under the reference case, oil and gas investment is estimated to average $8.3 billion (C$1989) annually over the next 10 years before increasing to $11.5 billion annually over the rest of the forecast period. In the alternative scenario, oil and gas expenditures are projected to average $5.6 billion (C$1989) annually until 2000, at which point they will increase to $9.4 billion (which is about 20 per cent below the level reached under the reference case).

6. Summary and Conclusions

Under both scenarios, oil supply is projected to be relatively stable for the next five years, before declining until the late 1990s and then rebounding over the remainder of the forecast period. Under the reference case, oil supply surpasses the current level of production by 15 per cent towards the end of the forecast period. Under the alternative case, oil supply falls short of 1988 production by 10 per cent.

Non-conventional sources are expected to play a significant role in Canada's future oil supply. Under both price scenarios, supply from non-conventional sources is projected to increase from 20 per cent of total oil supply in 1988 to around 60 percent by the end of the forecast period. Light crude oil's share, however, is projected to drop only slightly over the long term, in spite of the rapid decline in conventional light crude supply.

The major projects included in these projections involve long lead times and require significant capital outlays. Such projects are usually subject to a large number of risks and uncertainties. Other key assumptions of the oil supply projections include the level of reinvestment of industry cashflow, reserve costs, the oil/gas expenditure ratio, reserve potential and the level of production from bitumen projects.

Under the reference case, Canada is expected to become a net oil importer by 2010, more than 15 years later than in the alternative case. In 2020, net imports are projected to comprise 20 per cent of demand in the reference scenario and 45 per cent in the alternative scenario. Canada is still, however, expected to be a large exporter of heavy oil under both scenarios.

VII. NATURAL GAS SUPPLY CAPABILITY AND TRADE

1. Introduction

Domestic demand and export sales of natural gas continued to grow in 1988, reflecting adjustments to a more market-oriented environment, lower prices and improved accessibility to U.S. pipelines. Gas exports to the U.S reached 1.3 tcf in 1988, the highest level in history causing near capacity utilization of the Canadian pipeline system over the peak winter months. Exports are expected to continue to increase over the long term. In spite of the recent improvements in gas market conditions, significant surpluses of productive capacity still exist in Canada. In fact, over the long term Canadian productive capacity is expected to be sufficient to meet both increasing domestic and export requirements.

2. Natural Gas Resources

Canada's natural gas resource base is enormous, as shown in table 7.1.

Table 7.1

MARKETABLE NATURAL GAS RESERVES AND POTENTIAL
As of December 31, 1987

	Remaining Established Reserves (tcf)	Remaining Potential * (tcf)
Conventional Areas		
British Columbia	8.0	n\a
Alberta	57.7	n\a
Saskatchewan	2.0	n\a
Ontario and East	0.3	n\a
Northwest Territories	0.4	n\a
TOTAL	68.4	153
Frontiers		
Mackenzie Delta-Beaufort	5.3	68
Arctic Islands and Eastern Arctic Offshore	11.4	111
Mainland Territories	-	11
West Coast Offshore	-	69
East Coast Offshore	-	3
Hudson Bay	-	3
	16.7	272
TOTAL CANADA	85.1	425

*Includes Remaining Established Reserves
Sources: Established reserves for Western Canada are from the National Energy Board's (NEB's) Annual Report (1988) and remaining potential is derived from the Geological Surveys of Canada estimate (GSC).

According to the NEB, approximately 80 per cent of established reserves are located in western Canada. More than 60 per cent of the remaining potential is in the frontier regions. It should be recognized, however, that there is a fair degree of uncertainty in the assessment of resource potential. In its most recent forecast, the NEB used the Geological Survey of Canada's (GSC) estimate of technical ultimate gas potential. In its 1986 projection, however, the NEB used its own estimate of ultimate potential, which was lower than the GSC's. Recent comments by ERCB officials suggest that actual Canadian gas reserve estimates could be significantly higher than current estimates.

3. Productive Capacity

According to our projections, natural gas productive capacity increases from the 1988 level of 4.5 tcf to around 6 tcf in 2005 and to 7 tcf by 2020 in the reference case. Under the alternative case, productive capacity increases to 5 tcf in 2005 and to 6 tcf by 2020. The reserve additions required for these supply projections are about 130 tcf and 115 tcf under the reference and alternative cases respectively. These reserve additions could be attained with about 40 per cent of industry oil and gas expenditures under the reference case and 45 per cent under the alternative case (see table 6.5). Under both scenarios, the annual average reserve additions over the projection period are somewhat lower than during the 1970s, a period in which rising demand and the regulatory environment combined to provide strong incentives for gas exploration and development. Estimated gas-directed drilling was as high as 70 per cent during this period.

Table 7.2

NATURAL GAS RESERVE ADDITIONS
Annual Average
(tcf)

	Reference Case	Alternative Case
1988-1997	3.3	2.5
1998-2007	5.0	4.3
2008-2017	3.8	3.7
2018-2020	3.0	2.8
Total (1988-2020)	130	113.4

Under the reference case, production from the Mackenzie Delta is assumed to commence in 1997, when the average field price in Alberta is projected to be around $2.60/mcf ($1989). Peak production of 440 bcf from this area is assumed to be attained in 1999 and maintained throughout the forecast period (as shown in appendix 6). Beyond 2005, no distinction is made on whether the reserve additions required to meet the supply projections would be added from the frontiers or from conventional areas.

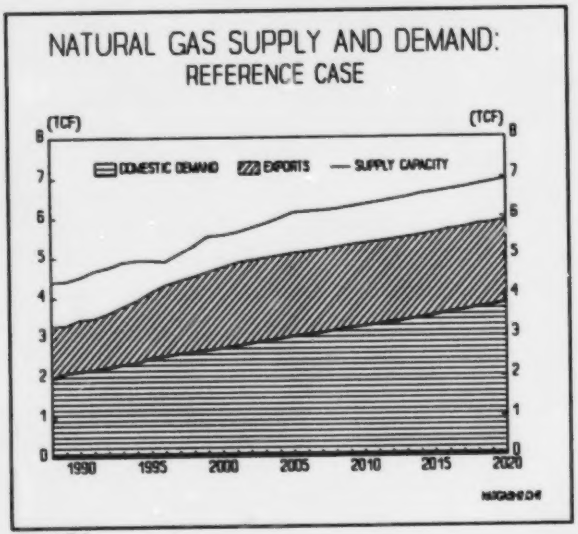

Chart 7.1

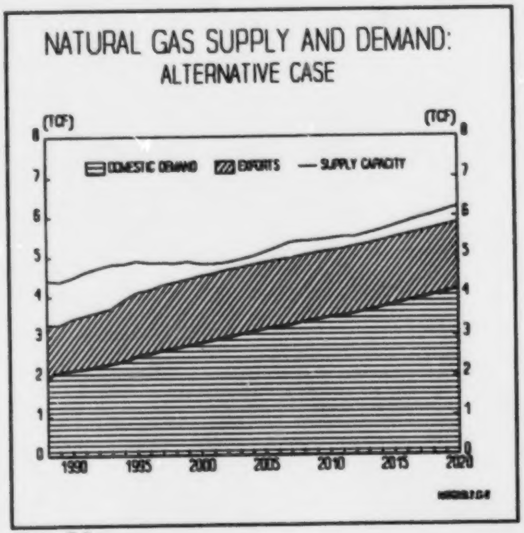

Chart 7.2

4. Exports

There are many differing views on Canadian natural gas exports to the U.S.[7] Projections by Petro-Canada show gas exports increasing to 1.7 tcf in 2000, while the U.S. Department of Energy (DOE) expects U.S. gas import requirements from Canada to increase to 2.3 tcf (see table 7.3). These differing views reflect uncertainty, not only over U.S. gas demand, but also about U.S. and Canadian gas resource bases. Some studies suggest that the U.S. gas reserve potential is in the range of 500 to 600 tcf at prices below US$3.00/mcf. It is not clear however whether these are just "inground" (finding and development) costs or the total supply price. A review of studies on Canadian economic gas resources revealed that information on supply price and finding and development costs were quite soft and fraught with definitional problems.

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[7] For discussions on differing views on U.S. gas import requirements and gas reserves potential, see S. Gera, "A Study of the U.S. and Canadian Gas Markets", Economic & Financial Analysis Branch, EMR, December, 1988.

Table 7.3

NATURAL GAS EXPORT PROJECTION*

(tcf)

	Petro-Canada Reference Case	DOE** Base Case	EMR Reference Case	EMR Alternative Case
1990	1.4	1.4	1.3	1.3
2000	1.7	2.3	2.1	1.7
2005	1.6	n/a	2.1	1.7
2010	1.4	n/a	2.1	1.7
2020	n/a	n/a	2.1	1.7

* Projections are not available (n/a) for all years .
** U.S. Department of Energy

In our assessment, gas exports under both scenarios would remain around 1.3 tcf until 1990, and then increase over the forecast period as the Canadian pipeline system is expanded. Under the reference case, gas exports are assumed to increase to 2.1 tcf by 2000 and remain constant for the rest of the forecast period. Under the alternative case, exports are projected to grow at a slower rate, reaching 1.7 tcf by 2000 and remaining at this level for the rest of the forecast period.

Export growth in the medium term stems from both growing U.S. demand and the availability of relatively cheaper Canadian gas. In the longer term, as prices increase, sufficient supplies will be added to meet total demand. In the reference case, excess supply capacity of around 500 bcf exists throughout the forecast period. Under the alternative case, excess capacity disappears by 2000. This causes gas prices to increase more rapidly than the price of oil, such that the balance between supply and demand is maintained.

5. Conclusions

Sufficient gas supplies are expected to be available to meet increasing domestic and export requirements in both the reference and alternative cases.

In the long term, total gas demand is almost identical under both price scenarios. In the reference case, some surplus capacity exists; under the alternative case, total supply capacity is only sufficient to meet demand over the long term. The uncertainty that surrounds Canadian gas resources appears to be more on the "upside" than on the "downside".

VIII. ELECTRICITY CAPACITY AND GENERATION

1. Introduction

An integrated supply-demand modelling framework has been used to develop projections of electricity capacity, generation and prices. Electricity demand estimates from IFSD are used in the electricity supply model UGENEX (Utility Generation Expansion Model) to determine when individual projects should be commissioned in order to meet electrical generation requirements. The profiles of these projects, in terms of size and type, were specified on the basis of development plans of Canadian utilities.

The forecast of capacity requirements forms the basis for projecting capital and operating costs, revenue requirements and electricity prices. Several key assumptions have been made regarding inflation, interest rates and utilities' financial targets (e.g. debt/equity ratios). Since the derived prices affect electricity demand, an iterative UGENEX-IFSD process is executed until results of both models converge.

2. Current Situation

Currently, the electric power industry has a significant amount of excess capacity in some regions of Canada (24 per cent nationally in 1987). This is the result of recent capacity additions in anticipation of high demand growth, similar to that of the 1960s and early 1970s, which did not materialize.

Since the 1970s, exports to the U.S. have accounted for an increasing share of Canadian electricity generation. This situation is not likely to continue for long; significant reductions in export volumes have been observed in recent years as domestic demand has strengthened. For Canada as a whole, net export volumes were down to 28 000 GWh in 1988 from 40 000 GWh in 1985.

Total electricity generation in Canada increased by an average of 4.3 per cent per year in the five years prior to 1988, but increased by only 1.4 per cent in 1988. Types of electric power generation vary from one province to another, reflecting resource availability. Hydro remains the main source of generation in Canada (although its share has slipped) accounting for 63 per cent of total electrical energy generation in 1988. Nuclear power accounted for 47 per cent of electric energy in Ontario and 34 per cent of electric energy in New Brunswick. Oil and gas accounts for a very small and shrinking share of total electricity generation.

3. Forecast Assumptions

Environment

In the future, Canadian utilities will have to deal with environmental issues. For example, electric utilities are significant producers of carbon dioxide. To some extent environmental concerns have been incorporated into the electricity supply forecast: the projections of generation from thermal coal plants have been lowered this year from last year's level. Ontario Hydro is planning to spend over $1 billion in the 1990s to install equipment to reduce sulphur dioxide emissions from coal plants, as well as to purchase more Canadian coal with a lower sulphur content. These costs have been included in our framework. Stringent emission standards or targets could have major impacts on electricity generation costs.

Demand Management

The high cost of new plants and environmental constraints have lead utilities to intensify their efforts on demand side management (DSM) and independent power production (IPP). Ontario Hydro anticipates that these initiatives will provide savings equivalent to some 5500 MW of generation by the year 2000, of which 4500 MW will be achieved through DSM activities, including load shifting, peak clipping and strategic conservation. More details on major utilities' DSM and IPP programs are available in EMR's publication entitled Demand Side Management in Canada (1989). To account for DSM programs in this forecast, an increase in load factors corresponding to the impact estimated by the utilities has been assumed.

Independent Production

It is assumed that gas combined cycle will contribute marginally to additional generation since the two major consumers, Ontario and Quebec, are located far from natural gas fields, which means high transportation and operating costs. It has been further assumed that the Hearn gas-fired steam plant (1000 MW) in Ontario will be recommissioned in the mid-1990s and operated by independent producers. (See Appendix A for assumptions on electricity projects).

Electricity Exports

Our model breaks exports into two categories: firm and interruptible. Since interruptible exports are determined endogenously in the model, assumptions are required only for firm export volumes. As discussed earlier, interruptible export volumes should drop in the 1990s as a result of declining surpluses. It is assumed that firm export volumes will increase until 2000, accounting for a greater share of total exports. They are then assumed to fall gradually as contracts reach their expiry date.

The evolution of electricity trade over the next 20 years is contingent upon the resolution of a number of critical issues, such as the construction of generating plants in the U.S. and the building of adequate transmission capability in Canada. Due to the long lead times required to build new nuclear and coal plants, some regions of the U.S. are not expected to meet their electricity requirements in the 1990s from local sources. Such options as the combined cycle technology, which takes a shorter lead time, are not economical for certain regions (such as the northeastern U.S.), because gas supply sources are distant and gas prices are projected to rise in the next decade.

This means there are good opportunities for Canada. Potential Canadian exporters are those utilities that can benefit from cheap hydro electric resources, such as Hydro-Quebec, Manitoba Hydro and BC Hydro. However, a limited increase in electricity exports has been assumed, due to regulatory constraints in the U.S. and Canada, the lack of transmission capability, contract and technical reliability considerations and the limited scope for coordinated planning between Canadian and American utilities.

4. Results

Generating Capacity

Electricity generating capacity[8] over the projection period is expected to increase at an average annual rate of 2.3 per cent under the reference scenario and 2.5 per cent under the alternative scenario. However, because of the current surplus, generation capacity is projected to increase over the period 1988 to 1995 at an average annual rate of only 1.9 per cent. Until 2005, the greatest increase comes from hydro; thereafter it comes from nuclear. Coal-fired generating capacity grows at a moderate rate over the entire period (table 8.2). Compared to 1988, Canada will require 50 per cent additional generating capacity by 2005 and twice as much by 2020.

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[8] By assuming higher energy efficiency improvements, the Canadian electrical utilities project lower generation capacity than EMR does. Although historical data support EMR's view a significant uncertainty remains in the forecast of energy efficiency.

Nuclear's share of electricity generation will remain at about 12 per cent until 2002 as the Darlington station in Ontario is completed and Lepreau II is assumed to come into service in the late 1990's. Given the lead time of about 12 years for new nuclear capacity, no other nuclear station could be operational in Ontario before then.

Although hydro is usually the cheapest form of electricity to produce, and is likely to remain so, the potential for further hydro development will ultimately run out. Thus, each province will be forced to confront the coal-nuclear trade-off. Both options engender different concerns, but the nuclear option has been proved to be cheaper and, environmentally, much less damaging. In its report released last year[9], the Advisory Committee on Energy Options concluded that the nuclear option should be sustained as a component of Canada's energy mix because it is a reliable source of power at relatively predictable and stable costs and has environmental advantages over coal.

It is therefore assumed that nuclear power generation is the favoured long term option for Ontario, Quebec, Newfoundland, New Brunswick, Manitoba and Saskatchewan. The increase in nuclear generation capacity between 1988 and 2020 is projected to be 32 GW (equivalent to 36 Darlington size units, where the Darlington station is comprised of 4 units). By 2020, British Columbia, the Northwest Territories and the Yukon territory would still have remaining hydro potential to meet additional demand requirements.

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[9] Energy and Canadians into the 21st Century.

Table 8.1

TOTAL GENERATING CAPACITY
share (%)

	Hydro	Nuclear	Coal	Other	Total (GW)
Reference					
1988	59	12	16	13	109.1
1995	57	12	16	15	124.6
2005	60	11	16	13	163.9
2020	52	20	17	11	225.5
Alternative					
1988	59	12	16	13	109.1
1995	57	12	16	15	124.2
2005	60	12	15	13	166.9
2020	50	22	17	11	238.0

Table 8.2

GENERATING CAPACITY
Major Provinces
(MW)

Reference

	Hydro	Nuclear	Coal	Others	Total
Ontario					
1988	8 461	10 526	10 420	4 436	33 843
2005	11 380	16 300	11 923	5 972	45 575
2020	11 380	31 050	16 423	5 972	64 825
Quebec					
1988	30 254	685	0	3 159	31 098
2005	51 281	685	0	2 515	54 481
2020	59 452	9 185	0	5 190	73 827
British Columbia					
1988	12 903	0	0	2 578	15 481
2005	13 203	0	2 120	4 645	19 968
2020	22 683	0	2 120	2 803	27 606
Alberta					
1988	780	0	4 465	2 326	7 571
2005	2 458	0	6 972	3 350	12 780
2020	3 529	0	12 222	3 850	19 601

Electricity Generation

Between 1988 and 2020, Canadian electricity demand is projected to increase by 2.7 per cent annually under the reference scenario and 3.0 per cent annually under the alternative scenario. This is slightly higher than last year's estimate; the better-than-expected economic growth of recent years has induced Canadian utilities to revise their electricity demand projections upward. Hydro-Quebec, for example, is assuming strong demand growth under its 1988 Development Plan, and BC Hydro is preparing to add new capacity in the early 1990s. Last year, Ontario Hydro also revised its demand growth estimates for the short term.

As a result of current excess capacity, electricity generation will grow faster than capacity over the next few years. Coal-fired generation is projected to increase in the 1990s, as coal plants are used more intensively in Ontario to meet the increased demand and to bridge the delay in the installation of new nuclear facilities. Due to an expected increase in domestic demand in the short run and to the fact that, until 1992, projects are being built to meet peak demand periods, in the early to mid-1990's Hydro-Quebec might be forced to buy electricity from independent producers or neighbouring provinces, or to buy back firm contracts.

Table 8.3

TOTAL ELECTRICITY GENERATION

Share (%)

Reference	Hydro	Nuclear	Coal	Other	Total (Twh)
1988	63	16	18	3	484.9
1995	58	18	17	7	602.5
2005	59	15	19	7	811.4
2020	53	27	16	4	1137.0

Over the next few years, the current electricity surplus will be reduced as a result of a slower expansion of generation capacity, exports and increased domestic demand resulting from strong economic growth. Thus, surplus capacity is projected to decline from 40 per cent in 1987 to about 33 per cent in 1990, and to below 22 per cent after 2005 (table 8.4).

Table 8.4

SURPLUS GENERATION CAPACITY IN 1987

(%)

	Reserve Margin	Capacity Reserve Requirement	Net Surplus
Newfoundland	30	12	18
Prince Edward Island	47	15	32
Nova Scotia	61	20	41
New Brunswick	54	17	37
Québec	26	10	16
Ontario	49*	23	28
Manitoba	28	12	16
Saskatchewan	26	11	15
Alberta	29	22	7
British Columbia	24	18	6
Canada	40	16	24

* Capacity includes mothballed units.

5. Conclusion

Canada's electricity generating capacity is expected to increase by 50 per cent to 2005 and should double by 2020. Our forecast of capacity shares by different fuel types shows that coal capacity should fall slightly by 2005 and level off thereafter. Hydro's capacity share should peak at 58 per cent by 2005 (reference case), and fall to 50 per cent by 2020 as its economical potential is fully developed. The growth in generation capacity from other fuels rises sharply. Nuclear's capacity share should be relatively flat until 2005 (at 11-12 per cent), but rise to 20 per cent by 2020.

IX. COAL PRODUCTION AND TRADE

1. Introduction

Coal demand projections have been developed using the IFSD model. Coal production estimates have then been derived on the basis of domestic demand and export projections. Estimates of coal exports and imports were obtained from information provided by EMR's Coal and Iron Division.

2. Reserves

Canada's discovered coal reserves are substantial. According to the latest estimates, the portion of reserves that has been sufficiently delineated to be classified as recoverable is equivalent to 6578 megatons. This volume is almost 100 times the current annual production. Over 93 per cent of these reserves are located in the western provinces.

3. Production

Canadian coal production is determined principally by two markets: domestic electric utilities' demand for thermal coal and international demand for metallurgical coal (required by the Japanese and other Pacific Rim steelmakers). On a tonnage basis, the metallurgical exports, together with smaller quantities of thermal coal exports, represent 45 per cent of production. However, on a dollar-value basis, exports comprise 65 per cent of production.

Due to the high cost of transporting coal to central Canada, Ontario imports close to 80 per cent of its coal requirements from the U.S. Virtually all of the coal required by Ontario steelmakers, and about two-thirds of the coal required by Ontario Hydro, are sourced in the U.S. However, it is noteworthy that in recent years Ontario Hydro has been increasing its purchases of low-sulphur coal from western Canada in order to reduce acid gas emissions.Coal production is projected to increase steadily over time, at an average annual rate of 2.6 per cent from 1988 to 2005 in the reference case, and at 2.7 per cent in the alternative case. After 2005, these growth rates should drop to around 1.5 per cent. By 2020, coal production is projected to be about double the current level (chart 9.1). The increase in production is expected to be larger in western Canada than in the East.

4. Demand

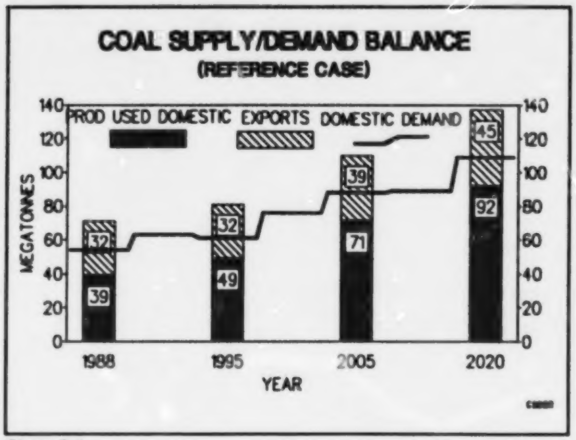

Chart 9.1

There are uncertainties with regard to both domestic demand and export prospects. The principal factors affecting domestic coal demand are Ontario Hydro's generation expansion plans after 1992 and Canadian environmental concerns. Ontario's coal requirements for electricity generation are expected to decline in the next few years as new nuclear capacity, now under construction, comes into service. The utility has not, however, announced its expansion plans beyond the completion of the Darlington nuclear station in 1992.

Based on projected electricity demand in Ontario, additional generation capacity could be required before 2000. Due to the long lead time required for construction, it is already too late to bring on new nuclear capacity before 2002. It is therefore assumed that a large share of the growth in electricity demand in the mid-to-late 1990s will be met by more intensive use of existing coal-fired thermal plants. There will also be some rehabilitation of retired coal plants, which will have to be retrofitted with improved emission control equipment.

After 2000, it is probable that Ontario will opt for increased use of nuclear generation because of environmental considerations, including legislated acid gas emission limits and the carbon dioxide - global warming implications of fossil fuels. Nevertheless, Ontario Hydro will retain a significant portion of coal in its generating mix to ensure diversity of supply and the flexibility to meet demand fluctuations. In Alberta, Saskatchewan and Nova Scotia, coal is assumed to continue as the dominant source of electricity generation (currently between 70 and 90 per cent). Under the alternative case, the demand for coal is not particularly sensitive to economic growth.

5. Exports

The coal industry worldwide -- including Canada -- has undertaken large capacity increases in recent years. Combined with stabilized world demand for metallurgical coal, this has resulted in intense competition among coal exporters. Canadian exporters are faced with relatively expensive transportation costs (due to long rail hauls to tidewater), and the Canadian dollar has appreciated in the past few years.

Future growth in international steam coal demand is expected to present selected market opportunities for Canadian exporters. Domestic producers are expected to maintain their position in the slower growing international metallurgical coal markets. Coal exports are projected to increase at a modest average annual rate of 1.2 per cent, reaching 39 megatons by 2005. Thereafter, exports will increase by an average annual rate of one per cent, reaching 45 megatons by 2020. These are much slower growth rates than the 8.5 per cent per year recorded during the past 10 years.

6. Conclusion

The demand outlook for Canadian coal hinges on a number of critical factors. These include Ontario Hydro's generation expansion plans after 1992, environmental concerns and coal's competitiveness on the international market. In spite of these uncertainties, coal production is projected to increase at an average annual rate of 2.1 per cent between 1988 and 2020.

X. ENVIRONMENTAL IMPLICATIONS

The main conclusion to be drawn from this report is that, despite slower economic and population growth, energy consumption will continue to expand at a rapid pace. Indeed, by the end of our forecast period, the amount of primary energy consumed is staggering almost twice that consumed in 1988. Although the rate of increase in oil consumption is lower than that of total energy consumption, in 2020, 72 per cent more oil will be used than in 1988.

This raises questions as to whether such growth can continue unchecked, and what policy implications are associated with this growth rate. In addition to supply (or depletion) and distribution problems, there are serious environmental concerns. These have recently seized the attention of Canadians, and policy-makers are being pressured into finding solutions to environmental problems on an urgent basis.

One of the major environmental issues is the greenhouse effect, which is caused by gas emissions that stem largely from energy combustion. According to a rough estimate reported by the Ontario Ministry of Energy, carbon dioxide dominates energy-related emissions, accounting for 98.5 per cent of total emissions by weight. Among energy sources, oil contributed almost half of the 1987 energy-related emissions of CO_2, with natural gas and coal each contributing about 25 per cent. Coal is by far the most carbonaceous fuel, followed by petroleum products and natural gas on the basis of their end-use applications.

On a sectoral basis, transportation and electric utilities are the dominant sources of CO_2 emissions, accounting for 27 and 22 per cent respectively. The residential and commercial sectors combined account for roughly another 20 per cent, while industry accounts for about 30 per cent.

Emission patterns for other gases differ somewhat from carbon dioxide. Motor vehicles account for roughly half the carbon monoxide and other volatile organic compounds (VOC) emissions. Thermal generating stations are the dominant energy-related source of sulphur and nitrogen oxides. The residential sector is the largest single source of methane emissions. Despite these variations, the overall pattern is reasonably similar across all the gases. This is because fossil fuel combustion produces emissions of all of these gases. Conversely, measures to reduce emissions of one of the gases could reduce emissions of all the gases.

Discussions are already taking place with a view to reducing CO_2 emissions. At a recent Toronto conference of scientists on climate change, it was suggested that CO_2 emissions be reduced by 20 per cent of the 1988 level by 2005 as an initial global goal. Assuming proportionality, this means that primary fossil fuel consumption must be cut by 50 per cent -- a tall order. For example, to achieve the 20 per cent reduction target for CO_2 (assuming no additional emissions due to increased energy use between 1988 and 2005), it would be necessary to displace virtually all coal, or half of all petroleum products, or all residential and commercial fossil fuels, or all automotive fuel with an energy source that produces no CO_2 emissions.

Gas emissions can be reduced either through improvements in energy-use efficiency and R & D, or through substitution of more carbonaceous fuels with less carbonaceous fuels. All of these measures would require international cooperation; policies and programs undertaken by Canada alone could affect our international competitiveness.

It is beyond the purview of this outlook to attempt to predict what decisions might be taken. Regardless of the policy mix that is chosen, however, we can expect a move away from coal and heavy fuel oil, and toward electricity and other renewable energy forms, such as solar and biomass. At the same time, it must be noted that a reduction in carbonaceous fuels cannot be achieved without a parallel and planned increase in the production of less carbonaceous fuels. At this stage, the two most likely replacement candidates are hydro and nuclear power. The share of electricity for the residential, commercial and industrial sectors averages 46 per cent in 1990 and slowly creeps up to 51 per cent by 2020. Electricity use has a high regional concentration, so that there is much room for increased electricity use in certain provinces, problems of distribution notwithstanding. Among measures that could easily be implemented in the residential and commercial sectors are higher building standards. In order to encourage energy conservation, Ontario and British Columbia have already implemented electricity demand management programs aimed at postponing capacity additions. There is also likely to be a move toward greater use of solar energy and heat recovery and storage systems.

However, there is no guarantee that Canada can quickly march down the electricity route. Hydro potential is reaching its peak in Quebec, the country's largest producer, and the province's internal market is nearing saturation point. The rest of the country is more likely to rely on nuclear energy. However, there are some who remain unconvinced that its benefits outweigh its risks.

Given the barriers to the development of clean(er) energy alternatives, the long lead times required, and the public's insistance for early results, a broad strategy for energy efficiency is most likely to be implemented. In this case, demand adjustments would occur more rapidly. As well, all sectors would be affected, perhaps foremost transportation.

Regardless of what happens on the domestic front, the route chosen in the U.S. will have a major influence on Canadian energy markets. The strong public opposition to nuclear power in the U.S. reduces that country's options considerably and probably means a longer period of reliance on carbonaceous fossil fuels. Therefore, the selection of different instruments in both countries could create some imbalances in the North American energy market.

Finally, environmental concerns are international in scope. For this reason, Canada is working closely with other countries, particularly within the Intergovernmental Panel on Climate Change (IPCC) to carry out scientific and energy studies and to develop an international framework convention on climate change for the World Conference on Environment and Development in 1992.

APPENDIX A: SUPPLY ASSUMPTIONS

Key Oil & Gas Supply Assumptions

Reference Case	Alternative Scenario
• Reinvestment ratio of 80 per cent of cashflow lagged one year until 2000, and 75 per cent for the rest of the forecast period. The corresponding ratios based on the current year cashflow average 74 per cent and 72 per cent respectively.	• Reinvestment ratio of 80 per cent of cashflow lagged one year until 2005, and 75 per cent for the rest of the forecast period. The corresponding ratios based on the current year's cashflow average 74 per cent and 72 per cent respectively.
• Oil's share of expenditures on conventional activity declines from 65 per cent in 1988 to a low of 55 per cent in the mid-1990s, before rebounding to current levels by the end of the forecast period. Overall, oil expenditure's share averages 60 per cent over the forecast period.	• Oil's share of expenditures on conventional activity declines from 65 per cent in 1988 to a low of 45 per cent in the mid-1990s before rebounding to current levels by the end of the forecast period. Overall, oil's share averages 55 per cent over the forecast period.
• Oil reserve costs of $8.75/bbl ($1989) and gas reserve costs of $0.75/mcf. Finding and development costs remain constant in real terms until 1993, before increasing by two per cent for the rest of the forecast period.	• Oil reserve costs of $8.75/bbl ($1989) and gas reserve costs of 0.75/mcf. Finding and development costs remain constant in real terms until 2000, before increasing by two per cent for the rest of the forecast period.

Assumed Development of Non-Conventional Oil Supplies

Reference Case	Alternative Case
East Coast	
• First production in 1996. Maximum production in 1999 at 150 mb/d.	• First production in 1998. Maximum production in 2002 at 150 mb/d.
- Hibernia production commences in 1996. Maximum production in 1998 at 110 mb/d.	- Hibernia production commences in 1998. Maximum production in 2000 at 110 mb/d.
- Terra Nova commences production in 1998. Maximum production in 1999.	- Terra Nova commences production in 2001. Maximum production in 2002.
Beaufort	
• Gas - - First production in 1997. Maximum production in 1999 at 440 bcf.	• Gas - - No production.
• Oil - - First production in 2000. Maximum production in 2002 at 200 mb/d.	• Oil - - No production.
Mining Plants	
• Existing - Suncor debottlenecking of 20 mb/d, for start-up in 1993.	• Existing - Suncor debottlenecking of 20 mb/d, for start-up in 1995.
• New Plants/Major Expansions - Two plants of 70 mb/d for start-up in 1998 and 2002.	• New Plants/Major Expansions - One plant of 70 mb/d for start-up in 2002.
New Upgraders	
• New unit for start-up in 1993.	• New unit for start-up in 1993.

Bitumen Production (mb/d)

1988	130	130
2000	305	206
2005	352	243
2010	406	308
2020	503	428

The following committed projects were included in the electricity supply model UGENEX:

Province	Name of Project	Size (MW)	Type*	Date of Commission
Newfoundland	Holyrood	25	O	1988
	Paradise River	8	H1	1988
	Holyrood	25	O	1989
Nova Scotia	Trenton	150	C	1991
	New Coal A	150	C	1993
Quebec	Manic 5 PA	1056	H2	1989
	La Grande 2A	1900	H2	1991-1992
	La Grande 1	1310	H1	1993-1994
	Laforge 1	820	H1	1995
	Brisay	380	H1	1995
Ontario	Darlington No. 1	881	N	1990
	Darlington No. 2	881	N	1989
	Darlington No. 3	881	N	1991
	Darlington No. 4	881	N	1992
Manitoba	Limestone Unit 1	256	H1	1990
	Limestone Unit 2	640	H1	1991
	Limestone Unit 3	384	H1	1992
Saskatchewan	Gas Turbine	50	GT	1990
	Gas Turbine	50	GT	1990
	Gas Turbine	50	GT	1991
	Shand	300	C	1992
	Estivan	65	C	1992
Alberta	Genesee 2	406	C	1989
	Sheerness No. 2	380	C	1990
	Genesee 1	406	C	1991

* Symbols used are:

O - Oil
C - Coal
N - Nuclear

H1 - Peak Hydro
H2 - Base Hydro
GT - Gas Turbine

APPENDIX B: REFERENCE CASE TABLES

B.1 Macroeconomic Assumptions
B.2 World and Domestic Crude Oil Prices
B.3 Domestic and Export Natural Gas Prices
B.4 Electricity Price Determination
B.5 Comparative Fuel Price by Sector
B.6 Supply and Demand for Petroleum
B.7 Supply and Demand for Natural Gas and LPGs
B.8 Electricity Supply and Demand
B.9 Summary Results - Energy Demand

TABLE B.1: MACROECONOMIC ASSUMPTIONS   REGION: CANADA

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	REAL DOMESTIC PRODUCT (RDP): (CONSTANT 81$)										
RDPC	RDP - TOTAL......................	379.24	394.62	404.08	410.15	425.33	464.21	522.64	592.47	664.33	829.89
RDPAGC	- AGRICULTURE..............	11.48	10.59	11.59	11.88	12.74	13.51	14.98	16.68	18.46	22.50
RDPINC	- INDUSTRIAL...............	125.26	132.78	135.25	136.71	142.45	158.38	182.80	213.46	245.30	320.18
RDPIRC	- IRON & STEEL (NAT'L).	1.42	1.53	1.56	1.56	1.63	1.81	2.11	2.46	2.84	3.74
RDPCPC	- COMMERCIAL & PUBLIC ADMIN	200.33	208.10	213.70	217.33	221.46	241.04	267.96	297.88	323.60	381.89
RDPAVC	- AVIATION (NAT'L).........	2.83	2.96	3.02	3.08	3.22	3.58	4.13	4.83	5.57	7.34
RDPRLC	- RAIL (NAT'L).............	3.02	3.17	3.22	3.30	3.44	3.84	4.44	5.20	6.01	7.91
RDPPCC	RDP PER CAPITA................	14807.	15244.	15440.	15500.	15898.	16636.	17893.	19518.	21167.	25094.
YPDKC	REAL PERSONAL DISPOSABLE INCOME	268.09	274.80	279.19	281.43	288.18	312.23	345.57	381.17	420.01	507.00
YPDPCC	PERS'L DISP. INCOME PER CAPITA.	10467.	10615.	10668.	10636.	10772.	11189.	11831.	12557.	13382.	15330.
	PRICES AND COSTS: (1981=1.0)										
PWPIUS	U.S. PRODUCER PRICE (1982=100).	102.8	106.9	111.4	115.1	119.5	138.1	168.9	206.1	250.7	371.1
PGDP	GDP DEFLATOR - TOTAL...........	1.307	1.354	1.411	1.459	1.512	1.746	2.128	2.584	3.129	4.587
PGDPAG	- AGRICULTURAL....	1.063	1.091	1.114	1.146	1.193	1.400	1.710	2.089	2.551	3.805
PGDPIN	- INDUSTRIAL......	1.296	1.345	1.401	1.448	1.503	1.733	2.096	2.538	3.049	4.427
PGDPCP	- COMMERCIAL......	1.357	1.415	1.480	1.535	1.599	1.873	2.309	2.850	3.485	5.208
PCXDE	PERS. CONS. DEFLATOR EX. ENERGY	1.379	1.435	1.489	1.545	1.603	1.857	2.232	2.716	3.304	4.891
CPI	CONSUMER PRICE INDEX...........	1.382	1.438	1.502	1.554	1.616	1.878	2.294	2.804	3.408	5.045
PFX	EXCH. RATE ($CAN PER UNIT $US).	1.326	1.229	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250
RIPRVB	AVG. YIELD - 10 PROV'L BONDS...	10.8	10.6	11.3	10.5	10.0	10.0	10.0	10.0	10.0	10.0
	DEMOGRAPHIC: ('000)										
POPC	TOTAL POPULATION...............	25613.	25867.	26172.	26461.	26754.	27904.	29209.	30355.	31386.	33071.
HHC	TOTAL HOUSEHOLDS...............	9556.	9728.	9893.	10052.	10213.	10797.	11494.	12261.	13079.	14882.
RHHSTC	SINGLE / TOTAL HOUSEHOLDS......	0.640	0.638	0.637	0.636	0.635	0.633	0.630	0.625	0.619	0.605
	LABOUR MARKET:										
POPLFC	LABOUR FORCE SOURCE POP. ('000)	19825.	20065.	20298.	20525.	20732.	21527.	22476.	23459.	24485.	26674.
LFC	LABOUR FORCE ('000)............	13121.	13383.	13584.	13785.	13938.	14567.	15394.	16267.	17030.	18663.
EMPC	TOTAL EMPLOYMENT ('000)........	11954.	12342.	12533.	12615.	12823.	13357.	14163.	15183.	15934.	17427.
URATEC	UNEMPLOYMENT RATE (%)..........	8.89	7.78	7.74	8.49	8.00	8.31	7.99	6.67	6.44	6.62
RDPPEC	LABOUR PRODUCTIVITY (RDP/EMP)..	31724.	31974.	32242.	32513.	33169.	34755.	36901.	39023.	41694.	47620.
	PASSENGER VEHICLES:										
NPVSTC	SALES - VOLUME...........('000)	1065.1	1073.9	1042.4	1070.9	1140.3	1236.1	1308.8	1428.6	1554.7	1835.8
ENPVS	- EFFICIENCY....(L/100KM)	10.9	10.8	10.8	10.6	10.5	10.1	9.6	9.5	9.5	9.4
KTPVSC	STOCK - VOLUME...........('000)	9979.0	10181.1	10303.1	10446.1	10647.2	11537.0	12631.1	13724.4	14890.5	17580.6
EKTPVC	- EFFICIENCY....(L/100KM)	11.5	11.7	11.4	11.2	11.1	10.6	10.1	9.7	9.5	9.4
KTMAC	MANUFAC'NG CAPITAL STOCK ($81B).	120.759	130.660	133.727	135.541	142.673	162.456	192.785	230.866	270.414	363.422
KGDSC	NATURAL GAS DIST. CAPACITY (MCM)	896.	898.	901.	909.	919.	942.	965.	987.	1011.	1055.
DDAYSC	HEATING DEGREE DAYS (NORM=1)....	0.896	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

TABLE B.2: WORLD AND DOMESTIC CRUDE OIL PRICES
($/CUBIC METRE)

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	WEST TEXAS INTERMEDIATE: ($US)										
PWTCU	CUSHING	120.56	100.53	113.27	117.80	126.61	168.90	242.21	294.63	358.50	530.68
PWTCUR	REAL ($1989)	130.41	104.58	113.27	113.27	117.06	133.48	157.34	157.31	157.32	157.32
TOCUCH	TRANSPORTATION TO CHICAGO	2.83	2.83	2.89	2.94	3.00	3.22	3.57	3.94	4.36	5.31
TRFDU	U.S. REFINERY TAX	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
PWTCH	CHICAGO	123.91	103.88	116.68	121.26	130.12	172.64	246.30	299.09	363.38	536.50
	BRENT ($US)										
PBRNS	NORTH SEA (F.O.B)	115.83	94.18	108.40	113.00	121.80	163.66	235.67	287.04	349.69	518.67
TOLOSS	OCEAN LOSS	0.46	0.38	0.43	0.45	0.49	0.65	0.94	1.15	1.40	2.07
TONSPO	TRANSPORTATION TO PORTLAND	4.68	5.05	5.16	5.24	5.34	5.75	6.36	7.03	7.76	9.47
TOPOMO	TRANSPORTATION TO MONTREAL	4.06	4.66	4.76	4.83	4.93	5.30	5.87	6.49	7.16	8.73
PBRMO	MONTREAL (C.I.F)	125.04	104.27	118.75	123.52	132.56	175.36	248.84	301.71	366.01	538.94
	LANDED IMPORT COST:										
PCRICA	IMPORT MIX ADJUSTMENT	-4.15	-2.51	-3.56	-3.71	-3.98	-5.26	-7.47	-9.05	-10.98	-16.17
PCRMU	AT MONTREAL (CIF) ($US)	120.89	101.76	115.19	119.82	128.58	170.10	241.37	292.66	355.03	522.78
PFX	EXCH. RATE ($CAN PER UNIT $US)	1.326	1.229	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250
PCRMT	AT MONTREAL (CIF) ($CDN)	160.27	125.05	143.98	149.77	160.72	212.63	301.71	365.83	443.79	653.47
	CANADIAN PAR:										
PPACH	CHICAGO ($US)	122.34	102.50	115.51	120.05	128.82	170.91	243.83	296.10	359.74	531.14
TRFPAU	U.S. IMPORT TARIFFS	1.64	1.56	1.42	1.25	1.09	0.74	0.74	0.74	0.74	0.74
TOBOCH	TRANSPORTATION TO U.S. BORDER	2.98	2.97	3.04	3.09	3.14	3.38	3.74	4.14	4.57	5.57
TOBOED	TRANSPORTATION TO EDMONTON	2.29	2.52	2.58	2.62	2.67	2.87	3.17	3.50	3.85	4.67
PPAED	EDMONTON ($CDN)	153.05	117.29	135.61	141.36	152.41	204.91	295.23	359.66	438.23	650.20
	REFINERY CRUDE COST ($CDN):										
PCRATA	ALBERTA	149.25	114.75	129.90	135.42	146.00	196.29	282.81	344.54	419.80	622.85
PCRATO	ONTARIO	152.69	122.47	134.63	142.41	152.02	202.23	288.35	352.54	428.28	632.17
PCRATQ	QUEBEC	156.05	121.83	135.45	143.74	153.13	203.30	289.30	354.02	429.83	633.82
PCRATF	ATLANTIC	154.88	119.33	138.04	143.73	154.57	206.00	294.38	357.72	434.84	642.55

TABLE B.3: DOMESTIC AND EXPORT NATURAL GAS PRICES
($/GIGAJOULE)

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
	DOMESTIC PRICE AT ALTA. BORDER:										
PNGAB	AVERAGE NOMINAL	1.87	1.77	1.89	2.05	2.29	3.32	5.15	6.39	7.76	11.45
PRNGAB	AVERAGE REAL (1981=1.00)	1.43	1.31	1.34	1.40	1.51	1.90	2.42	2.47	2.48	2.50
PNGABR	RESIDENTIAL	2.24	2.10	2.20	2.20	2.49	3.43	5.34	6.64	8.07	11.92
PNGABC	COMMERCIAL	2.14	2.01	2.04	2.11	2.36	3.37	5.24	6.52	7.92	11.71
PNGABI	INDUSTRIAL	1.69	1.61	1.75	1.93	2.14	3.24	5.03	6.26	7.61	11.24
PGDSAB	DIRECT SALES	1.39	1.38	1.45	1.78	2.07	3.12	4.85	6.03	7.33	10.84
PCMPAB	SYSTEM GAS	1.80	1.69	1.85	1.98	2.17	3.28	5.09	6.33	7.70	11.38
GOPAR	TORONTO GAS/OIL PARITY	0.74	0.79	0.77	0.78	0.79	0.82	0.85	0.86	0.86	0.85
	EXPORT PRICE AT US BORDER:										
PNGXT	NOMINAL ($CDN)	2.43	2.19	2.32	2.49	2.73	3.78	5.61	6.97	8.47	12.51
PRNGXT	REAL ($CDN) (1981=1.00)	1.86	1.62	1.64	1.71	1.81	2.16	2.64	2.70	2.71	2.73
PFX	EXCH. RATE ($CAN PER UNIT $US)	1.326	1.229	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250
PNGXU	NOMINAL ($US)	1.83	1.77	1.85	1.99	2.19	3.02	4.49	5.58	6.78	10.01

TABLE B.4: ELECTRICITY PRICE DETERMINATION (NOMINAL)

REGION: CANADA

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	UTILITY FUEL INPUT PRICES: ($/GJ)										
PCCUEC	COAL	1.270	1.429	1.539	1.608	1.707	2.353	3.468	4.350	5.141	7.452
PHFUEC	HEAVY FUEL OIL	3.120	2.358	2.769	2.895	3.130	4.845	7.794	9.502	11.541	16.442
PDSUEC	DISTILLATES	7.480	7.458	6.780	7.041	7.515	9.685	12.951	15.442	18.907	27.185
PNGUEC	NATURAL GAS	1.690	1.915	1.840	1.846	2.216	3.266	5.146	6.942	8.481	11.903
PNUUEC	NUCLEAR	0.438	0.485	0.505	0.522	0.542	0.625	0.762	0.925	1.120	1.643
POFUEC	OTHER FUELS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	PLANNED COSTS: ($MILLIONS)										
FPETTC	TOTAL PLANNED COSTS	18058.3	18731.5	19843.3	20844.2	21973.7	28499.0	43046.8	60700.6	83209.7	145925.4
FPEOCC	PLANNED OPERATING COSTS	6605.5	7319.3	7830.6	8225.0	9054.4	12529.9	19745.8	27156.2	35089.3	62305.2
FPFULC	PLANNED FUEL COSTS	1735.6	1999.8	2125.0	2277.4	2610.2	4720.6	8627.2	11999.8	14757.2	25557.2
FIWSAC	WAGES AND SALARIES	2877.9	3217.6	3435.3	3601.4	3854.8	4806.3	6815.7	9422.9	12736.4	23023.3
FPEOOC	OTHER OPERATING COSTS	785.5	875.8	965.9	990.2	1146.7	1257.0	1883.1	2530.4	3401.8	6383.2
FITXSC	INDIRECT TAXES	732.7	755.7	777.1	811.4	853.9	1004.9	1361.7	1780.6	2291.8	3686.7
FIROYC	ROYALTIES	473.8	470.3	527.3	544.6	588.9	741.1	1058.2	1422.6	1902.1	3654.7
FIEFXC	FIXED COSTS	8913.1	9292.0	9472.8	9962.3	10334.8	12241.3	18068.1	26651.9	39041.0	74458.5
FIINTC	NET INTEREST COSTS	6728.5	7087.8	7142.1	7512.6	7753.7	9038.3	13361.9	19797.7	28764.6	55556.8
FIDEPC	DEPRECIATION	2184.6	2204.2	2330.7	2449.7	2581.1	3202.9	4706.2	6854.2	10276.4	18901.7
FIRETC	TOTAL RETURN ON NET EQUITY	1656.4	1616.1	1944.1	2186.1	2157.6	3393.7	3998.0	5515.3	7621.2	7551.3
FICRPC	PLANNED CONTRIB'N TO RESERVE	-8.4	-16.9	-29.2	-163.3	-221.0	-381.8	390.8	366.1	248.6	-141.3
FPFEXC	PLANNED EXCHANGE LOSS	379.3	-10.7	70.9	61.7	53.6	30.7	15.3	7.6	3.8	0.9
FIITXC	INCOME TAX	317.9	329.9	343.8	355.1	368.6	425.1	514.2	622.6	748.0	1086.1
FIEOXC	OTHER EXPENSES	194.5	201.9	210.4	217.3	225.6	260.1	314.6	381.0	457.7	664.6
	OTHER REVENUE FLOWS: ($MILLION)										
FISAXC	FROM NET EXTERNAL SALES	1481.7	920.1	1239.5	1208.9	1209.6	1901.2	3213.2	3683.5	4458.9	6561.4
FMRESC	EXTERNAL SALES	1741.7	1160.4	1718.3	1652.5	1443.8	2097.2	4452.0	5193.6	6267.7	9009.4
FMCEPC	EXTERNAL PURCHASES	260.0	240.2	478.8	443.5	234.2	196.0	1238.9	1510.1	1808.7	2448.0
FISUBC	SUBSIDIES	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
FIROTC	OTHER OPERATING REVENUE	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4
FIOTIC	OTHER INCOME	699.2	725.8	756.3	781.2	810.9	935.1	1131.1	1369.5	1645.5	2389.3
FMRRQC	PLANNED DOMESTIC REVENUE REQUIREMENTS ($MILLIONS)	15424.0	16632.2	17394.2	18400.7	19499.8	25209.4	38249.2	55194.3	76651.9	136521.4
VEUIPC	PLANNED INTERNAL SALES (GHW)	367444.	381532.	393922.	400584.	415833.	471553.	560613.	640291.	728065.	946324.
	AVERAGE PRICES: (CENTS/KWH)										
PELCAC	BASED ON REVENUE REQUIREMENTS	4.327	4.483	4.442	4.633	4.757	5.669	7.332	8.942	10.759	14.646
PELAAC	ANNOUNCED PRICES	4.327	4.549	4.646	4.691	4.809	5.311	6.721	8.657	10.337	14.297
PELFAC	FORECAST PRICES	4.327	4.549	4.676	4.791	4.943	5.482	7.049	8.995	10.771	14.710

TABLE B.5: ENERGY PRICES - THERMAL UNITS REGION: CANADA
($/GIGAJOULE)

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	ENERGY PRICE INDEXES (1981=1.0)										
PDIRAC	RESIDENTIAL..................	1.41	1.47	1.55	1.59	1.67	1.92	2.51	3.17	3.87	5.47
PDICPC	COMMERCIAL...................	1.47	1.50	1.57	1.61	1.68	1.90	2.45	3.14	3.84	5.42
PDIINC	INDUSTRIAL...................	1.36	1.35	1.43	1.46	1.51	1.77	2.34	2.95	3.60	5.06
PDITRC	TRANSPORTATION...............	1.31	1.32	1.45	1.55	1.59	1.95	2.54	3.10	3.77	5.57
PDISDC	TOTAL SECONDARY DEMAND......	1.37	1.39	1.48	1.54	1.60	1.88	2.46	3.08	3.76	5.37
	REGIONAL SECTORAL PRICES: ($/GJ - EFFICIENCY ADJUSTED)										
PULFRC	LFO - RESIDENTIAL..............	11.41	12.18	13.11	13.68	14.40	17.83	23.53	28.78	35.03	51.89
PULFCC	- COMMERCIAL...............	9.14	9.68	10.45	10.89	11.48	14.23	18.84	23.06	28.05	41.50
PUHFIC	HFO - INDUSTRIAL...............	3.61	2.90	3.32	3.52	3.78	5.16	7.54	9.24	11.23	16.58
PUHFCC	- COMMERCIAL...............	3.87	3.19	3.63	3.84	4.12	5.60	8.14	9.96	12.10	17.87
PUNGRC	NATURAL GAS - RESIDENTIAL......	7.59	7.50	7.90	8.07	8.71	10.95	15.15	18.67	22.63	33.27
PUNGCC	- COMMERCIAL.......	5.43	5.40	5.58	5.75	6.20	7.99	11.18	13.80	16.77	24.82
PUNGIC	- INDUSTRIAL.......	3.97	3.64	3.71	3.70	3.83	5.29	7.71	9.56	11.62	17.16
PUELRC	ELECTRICITY - RESIDENTIAL......	13.02	14.02	14.64	15.04	15.55	16.93	21.44	27.55	33.77	46.59
PUELCC	- COMMERCIAL.......	16.46	17.10	17.84	18.25	18.79	20.34	25.69	33.31	40.84	56.76
PUELIC	- INDUSTRIAL.......	9.41	9.72	10.16	10.47	10.81	11.79	14.88	19.03	23.29	31.91
	PRICE RATIOS: (EFFICIENCY ADJ'D)										
	RESIDENTIAL:										
RPEORC	ELECTRICITY / LIGHT FUEL OIL	1.14	1.15	1.12	1.10	1.08	0.95	0.91	0.96	0.96	0.90
RPEGRC	ELECTRICITY / NATURAL GAS...	1.72	1.87	1.85	1.86	1.79	1.55	1.42	1.48	1.49	1.40
RPOGRC	LIGHT FUEL OIL / NATURAL GAS	1.50	1.62	1.66	1.70	1.65	1.63	1.55	1.54	1.55	1.56
	COMMERCIAL:										
RPEOCC	ELECTRICITY / LIGHT FUEL OIL	1.80	1.77	1.71	1.68	1.64	1.43	1.36	1.44	1.46	1.37
RPEGCC	ELECTRICITY / NATURAL GAS...	3.03	3.17	3.20	3.17	3.03	2.55	2.30	2.41	2.43	2.29
RPOGCC	LIGHT FUEL OIL / NATURAL GAS	1.68	1.79	1.87	1.89	1.85	1.78	1.69	1.67	1.67	1.67
	INDUSTRIAL:										
RPEOIC	ELECTRICITY / HEAVY FUEL OIL	2.61	3.35	3.06	2.98	2.86	2.28	1.97	2.06	2.07	1.92
RPEGIC	ELECTRICITY / NATURAL GAS...	2.37	2.67	2.74	2.83	2.82	2.23	1.93	1.99	2.00	1.86
RPOGIC	HEAVY FUEL OIL / NATURAL GAS	0.91	0.80	0.90	0.95	0.99	0.98	0.98	0.97	0.97	0.97

TABLE B.6: SUPPLY AND DEMAND - PETROLEUM
(THOUSANDS OF CUBIC METRES PER DAY)

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	DOMESTIC CRUDE OIL PRODUCTION:										
VCRPN	TOTAL	261.6	273.5	278.0	279.0	278.0	264.0	291.3	325.8	328.4	315.0
QCROD	- CONVENTIONAL OLD OIL	77.6	69.7	59.6	54.5	46.1	27.6	16.6	9.9	6.3	2.7
QSOPN	- SYNTHETIC OIL	28.7	31.7	33.5	33.5	33.5	36.3	47.3	58.3	58.3	58.3
QCRER	- ENHANCED RECOVERY	17.4	18.4	18.6	20.1	21.2	21.8	24.0	26.7	26.3	20.0
QCRNT	- NEW OIL	137.9	153.7	166.3	170.9	177.2	179.3	204.4	231.9	238.4	235.0
QCRUN	- NET HEAVY UPGRADING	0.0	0.0	0.0	0.0	0.0	-1.0	-1.0	-1.0	-1.0	-1.0
	DOMESTIC CRUDE OIL DEMAND:										
VRPDDC	PETROLEUM PRODUCTS DEMAND	227.6	238.6	239.6	241.8	247.4	269.9	291.5	315.5	340.1	405.8
VCRRG	REFINERY GAIN AND ADJUSTMENTS	12.7	12.9	13.0	13.0	13.1	13.6	14.0	14.5	15.0	16.3
QLPRN	NET REFINERY PROD'N OF LPG'S	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
QLPPR	- TOTAL REFINERY LPG PROD'N	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
VLPRP	- REFINERY LPG CONSUMPTION	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
VCRDD	DOMESTIC CRUDE OIL DEMAND	215.1	225.8	226.9	229.0	234.5	256.5	277.7	301.3	325.3	389.7
	STOCK CHANGES AND ADJUSTMENTS:										
VRPSC	REFINED PETROLEUM PRODUCTS	3.7	-3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VCRSC	CRUDE OIL	3.4	-2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PETROLEUM EXPORTS:										
VPEXT	TOTAL	125.7	149.6	143.7	147.4	141.8	114.5	121.1	117.2	112.6	111.5
VCRXT	- CRUDE OIL - TOTAL	98.7	112.8	105.7	107.4	101.8	74.5	81.1	77.2	82.6	91.5
VLMXS	- LIGHT & MEDIUM	41.9	49.9	45.0	45.0	38.0	20.0	10.0	0.0	0.0	0.0
VHVXS	- HEAVY (INCL. DILUENT)	56.8	62.9	60.7	62.4	63.8	54.5	71.1	77.2	82.6	91.5
VCRXE	- EXCHANGES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VRPXT	- PRODUCTS - TOTAL	27.0	36.8	38.0	40.0	40.0	40.0	40.0	40.0	30.0	20.0
	PETROLEUM IMPORTS:										
VPEMT	TOTAL	86.3	96.3	92.6	97.4	98.3	107.1	107.4	92.7	109.6	186.2
VCRMT	- CRUDE OIL	64.3	72.0	67.6	72.4	73.3	82.1	82.4	67.7	79.6	136.2
VRPMT	- PRODUCTS - TOTAL	22.0	24.3	25.0	25.0	25.0	25.0	25.0	25.0	30.0	50.0
VPEMN	NET PETROLEUM IMPORTS	-39.4	-53.3	-51.1	-50.0	-43.5	-7.5	-13.6	-24.5	-3.0	74.7

TABLE B.7: SUPPLY & DEMAND - NATURAL GAS & NGLS

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	MARKETABLE NATURAL GAS: (MCM)										
VNGPN	TOTAL PRODUCTION.............	79252.	92128.	93275.	97383.	99688.	120072.	135964.	143663.	151291.	166677.
VNGDD	DOMESTIC DEMAND..............	51246.	56807.	59944.	61318.	62022.	70507.	77331.	85031.	92658.	108044.
VNGSC	STOCK CHANGE.................	-83.	0.	0.	0.	0.	0.	0.	0.	0.	0.
VNGXT	EXPORTS......................	28[illegible]23.	35900.	34002.	36835.	38535.	50436.	59503.	59503.	59503.	59503.
VNGMT	IMPORTS......................	93.	309.	400.	500.	600.	600.	600.	600.	600.	600.
VNGAJ	STATISTICAL ADJUSTMENT.......	-160.	270.	270.	270.	270.	270.	270.	270.	270.	270.
	GAS PLANT NGLS (KCM/D)..........										
QLPRN	NET REFINERY PRODUCTION......	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
VGPPN	GAS PLANT PROD (INC SOLV FLD)	56.11	60.36	62.31	63.89	64.59	69.46	73.87	75.21	77.74	81.83
VPBPN	PROPANE & BUTANE...........	21.47	22.60	22.40	22.53	22.46	23.43	24.57	25.44	26.31	28.06
VETPN	ETHANE.....................	8.93	10.06	10.01	10.26	10.33	11.73	13.00	13.77	14.53	16.07
QPBRS	FROM REPROCESSING PLANTS...	25.70	27.70	29.90	31.10	31.80	34.30	36.30	36.00	36.90	37.70
VGPDD	DOMESTIC DEMAND..............	25.77	27.93	28.16	28.26	29.29	34.63	38.95	40.84	48.78	52.86
VGPER	REQUIREMENTS FOR EOR PROJECTS	15.50	19.80	19.60	18.20	14.60	6.90	3.50	0.00	0.00	0.00
VGPSC	STOCK CHANGE.................	2.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VGPAJ	STATISTICAL ADJUSTMENT.......	-0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VGPXT	NET EXPORTS (POTENTIAL)......	12.47	12.83	14.75	17.63	20.90	28.13	31.62	34.58	29.16	29.17

REPORT DATE: 30-OCT-89

TABLE B.8: ELECTRICITY SUPPLY & DEMAND
(GIGAWATT HOURS)

REGION: CANADA

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	GENERATING CAPACITY (MEGAWATTS)										
KEGCTC	TOTAL	100705.	109071.	111275.	112856.	115956.	124605.	144931.	163218.	182515.	225578.
KEGCUC	UTILITIES	94461.	101806.	103989.	105457.	108534.	116918.	137184.	155471.	174768.	217831.
KEGCIC	INDUSTRIES	6244.	7265.	7286.	7399.	7422.	7687.	7747.	7747.	7747.	7747.
	CANGEN PLANNED GENERATION:										
	TOTAL:										
VEUPXC	UTILITIES	446916.	445877.	467720.	474589.	491389.	554876.	655822.	745102.	839076.	1078937.
VEIPXC	INDUSTRY	36725.	38278.	40974.	41609.	41859.	50492.	51275.	51275.	51275.	51275.
	FOR DOMESTIC DEMAND:										
VELDXC	TOTAL	439668.	456431.	471535.	481270.	498744.	567045.	659751.	752611.	846693.	1084853.
	CANGEN PLANNED CAPACITY FACTOR:										
RGCUPC	UTILITIES	0.540	0.500	0.513	0.514	0.517	0.542	0.546	0.547	0.548	0.565
RGCIPC	INDUSTRY	0.671	0.601	0.642	0.642	0.644	0.750	0.756	0.756	0.756	0.756
	EXTERNAL SALES & PURCHASES:										
VELENC	NET EXTERNAL SALES	43956.	27724.	37159.	34928.	34504.	38323.	47347.	43767.	43659.	45360.
VELXNC	NET EXPORTS TO U.S.	43956.	27724.	37159.	34928.	34504.	38323.	47347.	43767.	43659.	45360.
VELESC	EXTERNAL SALES	47427.	34030.	39639.	37408.	36984.	41515.	50539.	46959.	46851.	47452.
VELXTC	EXPORTS	47427.	34030.	39639.	37408.	36984.	41515.	50539.	46959.	46851.	47452.
VELEPC	EXTERNAL PURCHASES	3471.	6306.	2480.	2480.	2480.	3192.	3192.	3192.	3192.	2092.
VELMTC	IMPORTS	3471.	6306.	2480.	2480.	2480.	3192.	3192.	3192.	3192.	2092.
VELIRC	NET INTER-REGIONAL TRANSFERS	0.	-2.	1.	1.	0.	1.	1.	0.	0.	0.
	GENERATION FOR DOMESTIC DEMAND: (INC. OWN-USE)										
VELDDC	TOTAL	439668.	457612.	470958.	480147.	497775.	565537.	661343.	755574.	848910.	1086464.
VEUDDC	UTILITIES	402943.	419334.	429983.	438538.	455917.	515045.	610068.	704298.	797635.	1035188.
VEIDDC	INDUSTRY	36725.	38278.	40974.	41609.	41859.	50492.	51275.	51275.	51275.	51275.
	TOTAL GENERATION:										
VELPNC	TOTAL	483641.	485334.	508118.	515076.	532279.	603861.	708691.	799341.	892569.	1131824.
VEUPNC	UTILITIES	446916.	447056.	467143.	473467.	490421.	553369.	657416.	748065.	841294.	1080548.
VEIPNC	INDUSTRY	36725.	38278.	40974.	41609.	41859.	50492.	51275.	51275.	51275.	51275.
	CAPACITY FACTOR:										
RGCUAC	UTILITIES	0.540	0.501	0.513	0.513	0.516	0.540	0.547	0.549	0.550	0.566
RGCIAC	INDUSTRY	0.671	0.601	0.642	0.642	0.644	0.750	0.756	0.756	0.756	0.756

TABLE B.9.1: SUMMARY RESULTS - ENERGY DEMAND
(PETAJOULES)

REGION: CANADA

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDC	SECONDARY DEMAND BY FUEL:	6098.1	6429.0	6546.8	6635.9	6814.4	7392.2	8096.8	8930.6	9855.5	12137.9
HRPSDC	RPP'S	2432.5	2545.1	2572.7	2577.7	2615.8	2740.2	2904.5	3161.2	3467.7	4212.5
HNGSDC	NATURAL GAS	1470.1	1598.6	1638.5	1690.0	1754.4	1934.7	2087.2	2271.4	2499.1	3065.3
HELSDC	ELECTRICITY	1452.2	1510.7	1555.1	1585.4	1643.5	1868.4	2184.2	2494.0	2800.6	3581.6
HCCSDC	COAL	49.7	51.7	50.1	49.0	50.0	51.4	57.7	66.5	76.5	101.2
HLPSDC	LPG'S	85.6	89.9	91.2	92.0	93.6	103.1	110.8	117.4	124.7	144.5
HKGSDC	COKE AND COKE OVEN GAS	173.5	181.2	183.0	183.0	187.6	199.8	218.2	239.1	259.9	305.4
HSTSDC	STEAM	27.6	32.9	32.8	32.9	35.4	39.8	47.1	54.8	63.3	84.1
HOFSDC	OTHER	406.8	418.9	423.4	425.9	434.1	454.9	487.2	526.2	563.7	643.3
	PRIMARY DEMAND BY SECTOR:										
HTSPDC	TOTAL	10385.6	10954.7	11208.4	11384.0	11716.1	12929.2	14495.3	16166.6	17934.6	22145.8
HTSEUC	END-USE DEMAND	6895.4	7292.6	7424.4	7521.4	7722.8	8382.5	9217.4	10165.0	11207.8	13623.1
HTSSDC	SECONDARY DEMAND	6098.1	6429.0	6546.8	6635.9	6814.4	7392.2	8096.8	8930.6	9855.5	12137.9
HTSRAC	RESIDENTIAL	1239.8	1330.2	1350.7	1370.8	1392.5	1466.7	1513.4	1552.9	1622.4	1834.6
HTSCPC	COMMERCIAL	848.3	880.5	913.0	936.1	959.7	1059.9	1183.6	1314.4	1427.3	1682.6
HTSINC	INDUSTRIAL	2285.6	2423.0	2465.9	2494.9	2587.1	2866.1	3264.2	3751.3	4276.1	5559.2
HTSTRC	TRANSPORTATION	1726.9	1795.2	1817.2	1834.1	1875.2	1999.5	2135.6	2312.1	2529.8	3061.5
HTSNEC	NON-ENERGY USE	797.4	863.6	877.6	885.5	908.4	990.3	1120.6	1234.3	1352.3	1485.2
HELIRC	INTER-REG'L ELEC. TRANSFERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HTSPCC	PRODUCER CONSUMPTION	470.1	506.9	515.9	529.5	546.3	622.9	699.7	768.6	838.7	1012.3
HTSCLC	INTERMEDIATE CONVERSION LOSS	3020.0	3155.3	3268.1	3333.1	3447.1	3923.8	4578.2	5233.0	5888.1	7510.4
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL	10385.6	10954.7	11208.4	11384.0	11716.1	12929.2	14495.3	16166.6	17934.6	22145.8
HRPPDC	RPP'S	3112.2	3279.0	3282.8	3314.7	3395.3	3717.7	4020.9	4358.3	4695.4	5606.4
HNGPDC	NATURAL GAS	1938.1	2148.4	2267.1	2319.1	2345.7	2666.6	2924.7	3215.9	3504.3	4086.2
HLPPDC	LPG'S	214.2	232.8	234.0	234.9	243.4	287.8	323.7	339.4	405.4	439.3
HCCPDC	COAL	1127.3	1155.2	1062.4	1068.3	1173.1	1335.9	1631.3	1857.5	1911.0	2348.0
HENPDC	NUCLEAR ELECTRICITY	765.3	824.5	885.3	950.8	1016.1	1146.5	1183.6	1299.0	1662.8	3143.5
HEHPDC	HYDRO ELECTRICITY	2826.9	2889.2	3024.6	3038.2	3074.4	3278.1	3879.8	4526.4	5147.9	5834.9
HOFPDC	OTHER (RENEWABLES)	406.8	425.6	452.2	458.0	468.2	496.6	531.2	570.2	607.8	687.4
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2C	PRIMARY DEMAND - TOTAL	8030.3	8514.3	8639.0	8762.7	9028.1	10021.6	11167.9	12338.5	13459.0	16245.7
HEHP2C	HYDRO ELECTRICITY	969.2	990.6	1037.0	1041.7	1054.1	1123.9	1330.2	1551.9	1765.0	2000.5
HENP2C	NUCLEAR ELECTRICITY	262.4	282.7	303.5	326.0	348.4	393.1	405.8	445.4	570.1	1077.8
	RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	118.59	125.77	125.52	125.51	125.31	125.06	121.20	116.24	113.63	112.86
RCDPRC	COM. DEMAND / COM. RDP	4.03	4.03	4.07	4.11	4.13	4.20	4.22	4.22	4.22	4.22
RIDPRC	IND. DEMAND / IND. RDP	18.25	18.25	18.23	18.25	18.16	18.10	17.86	17.57	17.43	17.36
RSDPCC	SECONDARY DEMAND / POP (GJ)	238.09	248.35	250.15	250.78	254.71	264.91	277.21	294.21	314.01	367.02
RSDPRC	" " / RDP/	16.08	16.29	16.20	16.18	16.02	15.92	15.49	15.07	14.84	14.63
REUPCC	END-USE DEMAND / POP (GJ)	269.22	281.71	283.68	284.25	288.66	300.40	315.57	334.87	357.10	411.93
REUPRC	" " / RDP	18.18	18.48	18.37	18.34	18.16	18.06	17.64	17.16	16.87	16.42
RPDPCC	PRIMARY DEMAND / POP (GJ)	405.48	423.17	428.27	430.23	437.93	463.34	496.27	532.59	571.43	669.64
RPDPRC	" " / RDP	27.39	27.76	27.74	27.76	27.55	27.85	27.73	27.29	27.00	26.69

TABLE B.9.2: SUMMARY RESULTS - ENERGY DEMAND
(PETAJOULES)

REGION: ATLANTIC

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDF	SECONDARY DEMAND BY FUEL:	468.8	485.3	507.2	515.2	524.2	547.6	577.5	616.4	667.2	790.4
HRPSDF	RPP'S	300.8	311.8	321.4	324.6	328.7	336.8	350.7	375.5	401.3	460.0
HNGSDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HELSDF	ELECTRICITY	102.0	105.5	113.7	117.7	122.0	134.6	146.1	155.4	175.4	229.0
HCCSDF	COAL	2.2	3.4	3.5	3.4	3.3	3.0	3.0	3.2	3.5	4.4
HLPSDF	LPG'S	5.4	6.4	6.8	7.0	7.3	8.4	9.3	9.8	10.7	12.9
HKGSDF	COKE AND COKE OVEN GAS	5.9	5.9	6.5	6.6	6.6	6.6	6.9	7.3	7.6	8.4
HSTSDF	STEAM	1.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
HOFSDF	OTHER	51.3	52.1	55.1	55.6	56.1	58.0	61.2	64.9	68.4	75.5
	PRIMARY DEMAND BY SECTOR:										
HTSPDF	TOTAL	988.0	1090.4	1037.7	1067.2	1142.8	1231.4	1424.6	1492.1	1591.6	1855.7
HTSEUF	END-USE DEMAND	491.1	508.6	531.8	540.3	549.8	574.0	604.6	645.0	697.5	824.3
HTSSDF	SECONDARY DEMAND	468.8	485.3	507.2	515.2	524.2	547.6	577.5	616.4	667.2	790.4
HTSRAF	RESIDENTIAL	85.3	89.3	90.8	92.2	93.6	95.6	96.4	99.3	105.6	121.7
HTSCPF	COMMERCIAL	64.1	64.1	66.1	67.5	69.0	74.6	81.3	88.2	94.2	107.2
HTSINF	INDUSTRIAL	164.3	167.7	183.8	187.2	190.1	200.5	217.0	236.2	261.3	321.6
HTSTRF	TRANSPORTATION	155.0	164.2	166.5	168.2	171.4	176.8	182.7	192.7	206.1	239.9
HTSNEF	NON-ENERGY USE	22.4	23.3	24.5	25.2	25.6	26.4	27.1	28.6	30.3	33.9
HELIRF	INTER-REG'L ELEC. TRANSFERS	247.5	297.6	217.9	225.2	274.4	305.9	443.9	443.9	446.0	443.9
HTSPCF	PRODUCER CONSUMPTION	35.1	38.5	37.6	39.5	41.9	45.1	45.9	49.7	52.7	64.9
HTSCLF	INTERMEDIATE CONVERSION LOSS	214.2	245.7	250.4	262.3	276.7	306.3	330.3	353.6	395.5	522.7
HTSPDF	PRIMARY DEMAND BY FUEL - TOTAL	988.0	1090.4	1037.7	1067.2	1142.8	1231.4	1424.6	1492.1	1591.6	1855.7
HRPPDF	RPP'S	425.9	472.1	439.4	463.7	497.2	525.9	515.4	563.5	575.0	679.1
HNGPDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.8	0.8	0.8
HLPPDF	LPG'S	5.4	6.5	6.9	7.1	7.4	8.6	9.5	10.0	10.9	13.1
HCCPDF	COAL	85.4	91.0	101.1	103.9	106.7	195.7	203.1	217.4	257.0	360.4
HENPDF	NUCLEAR ELECTRICITY	53.7	56.7	49.8	49.7	49.8	49.8	83.0	83.1	83.2	129.8
HEHPDF	HYDRO ELECTRICITY	366.4	407.2	380.6	382.3	420.5	387.4	546.3	547.1	591.0	591.8
HOFPDF	OTHER (RENEWABLES)	51.3	56.9	59.9	60.6	61.1	63.1	66.5	70.1	73.6	80.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2F	PRIMARY DEMAND - TOTAL:	712.0	785.6	754.9	783.4	833.7	944.0	1011.0	1077.9	1148.5	1381.6
HEHP2F	HYDRO ELECTRICITY	125.6	139.6	130.5	131.1	144.2	132.8	187.3	187.6	202.6	202.9
HENP2F	NUCLEAR ELECTRICITY	18.4	19.4	17.1	17.0	17.1	17.1	28.5	28.5	28.5	44.5
	RATIOS:										
RRDPHF	RES. DEMAND / HOUSEHOLD (GJ)	107.38	111.02	111.66	112.36	112.94	111.93	109.16	108.35	110.88	116.94
RCDPRF	COM. DEMAND / COM. RDP	4.17	4.00	4.06	4.11	4.14	4.22	4.27	4.29	4.30	4.34
RIDPRF	IND. DEMAND / IND. RDP	24.90	24.64	24.25	24.19	24.16	23.89	23.17	22.49	22.41	22.66
RSDPCF	SECONDARY DEMAND / POP (GJ)	205.10	211.48	220.20	222.82	225.92	233.03	242.94	257.65	277.93	327.45
RSDPRF	" " / RDP/	19.82	19.68	20.14	20.18	19.94	19.62	19.03	18.58	18.40	18.39
REUPCF	END-USE DEMAND / POP (GJ)	214.89	221.65	230.84	233.70	236.95	244.26	254.34	269.60	290.56	341.48
REUPRF	" " / RDP	20.77	20.62	21.12	21.16	20.91	20.56	19.93	19.44	19.24	19.18
RPDPCF	PRIMARY DEMAND / POP (GJ)	432.28	475.20	450.46	461.61	492.51	524.00	599.33	623.71	663.03	768.78
RPDPRF	" " / RDP	41.78	44.21	41.21	41.80	43.46	44.12	46.96	44.97	43.89	43.17

TABLE B.9.3: SUMMARY RESULTS - ENERGY DEMAND REGION: QUEBEC
(PETAJOULES)

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDQ	SECONDARY DEMAND BY FUEL:	1331.2	1396.4	1415.4	1435.8	1475.4	1586.8	1733.2	1930.9	2155.2	2699.4
HRPSDQ	RPP'S......................	521.2	559.5	565.7	568.7	577.4	594.0	614.4	656.5	715.3	861.7
HNGSDQ	NATURAL GAS................	189.3	195.0	196.2	202.1	213.3	237.2	260.7	287.9	319.7	397.7
HELSDQ	ELECTRICITY................	525.6	536.3	550.1	563.0	582.3	653.0	750.8	870.5	994.9	1293.1
HCCSDQ	COAL.......................	14.8	17.0	15.2	13.9	13.2	11.3	11.3	12.7	14.6	19.7
HLPSDQ	LPG'S......................	9.6	16.0	15.3	14.7	14.3	13.0	12.1	12.3	13.0	15.1
HKGSDQ	COKE AND COKE OVEN GAS......	2.5	2.6	2.6	2.6	2.6	2.7	2.9	3.2	3.5	4.1
HSTSDQ	STEAM......................	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDQ	OTHER......................	68.3	70.1	70.2	70.8	72.2	75.5	81.0	87.7	94.2	108.0
	PRIMARY DEMAND BY SECTOR:										
HTSPDQ	TOTAL......................	2417.9	2474.7	2647.6	2675.2	2674.9	2921.6	3299.1	3781.8	4300.6	5550.4
HTSEUQ	END-USE DEMAND.............	1426.7	1517.4	1542.1	1565.4	1608.4	1730.2	1885.6	2096.1	2333.5	2901.0
HTSSDQ	SECONDARY DEMAND..........	1331.2	1396.4	1415.4	1435.8	1475.4	1586.8	1733.2	1930.9	2155.2	2699.4
HTSRAQ	RESIDENTIAL..........	257.9	269.0	270.6	271.7	273.3	280.5	283.9	292.4	307.1	348.2
HTSCPQ	COMMERCIAL...........	177.1	184.2	190.0	194.0	198.4	216.9	239.5	263.0	283.0	327.1
HTSINQ	INDUSTRIAL...........	537.5	565.5	569.9	579.7	603.9	667.3	768.5	903.6	1050.1	1405.3
HTSTRQ	TRANSPORTATION........	359.1	377.6	384.9	390.4	399.8	422.0	441.4	471.9	514.9	618.7
HTSNEQ	NON-ENERGY USE...........	95.5	121.0	126.8	129.6	133.1	143.4	152.4	165.2	178.3	201.7
HELIRQ	INTER-REG'L ELEC. TRANSFERS.	-185.3	-274.0	-155.2	-179.5	-266.7	-305.9	-307.4	-307.4	-309.5	-307.4
HTSPCQ	PRODUCER CONSUMPTION........	87.1	96.5	97.9	99.5	102.4	114.6	127.8	144.2	162.3	205.7
HTSCLQ	INTERMEDIATE CONVERSION LOSS	1089.4	1134.9	1162.8	1189.8	1230.7	1382.6	1593.1	1848.8	2114.2	2751.0
HTSPDQ	PRIMARY DEMAND BY FUEL - TOTAL.	2417.9	2474.7	2647.6	2675.2	2674.9	2921.6	3299.1	3781.8	4300.6	5550.4
HRPPDQ	RPP'S......................	646.5	705.0	718.0	722.8	735.5	805.0	842.4	895.3	966.6	1146.1
HNGPDQ	NATURAL GAS................	192.7	203.6	204.9	210.8	222.2	246.6	270.5	298.2	330.6	410.0
HLPPDQ	LPG'S......................	12.2	24.5	23.8	23.2	22.8	29.0	32.3	37.2	41.8	47.1
HCCPDQ	COAL.......................	24.4	27.0	25.3	24.1	23.6	22.1	22.9	25.3	28.2	35.4
HENPDQ	NUCLEAR ELECTRICITY.........	48.9	55.7	55.8	55.8	55.8	55.8	56.5	56.6	51.0	683.4
HEHPDQ	HYDRO ELECTRICITY...........	1424.9	1388.8	1549.5	1567.6	1542.7	1687.6	1993.4	2381.5	2788.2	3120.5
HOFPDQ	OTHER (RENEWABLES).........	68.3	70.1	70.2	70.8	72.2	75.5	81.0	87.7	94.2	108.0
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2Q	PRIMARY DEMAND - TOTAL.........	1449.4	1525.4	1592.6	1608.4	1624.5	1775.9	1952.0	2179.6	2434.8	3050.7
HEHP2Q	HYDRO ELECTRICITY...........	488.6	476.2	531.3	537.5	528.9	578.6	683.5	816.5	955.9	1069.9
HENP2Q	NUCLEAR ELECTRICITY.........	16.8	19.1	19.1	19.1	19.1	19.1	19.4	19.4	17.5	234.3
	RATIOS:										
RRDPHQ	RES. DEMAND / HOUSEHOLD (GJ)	98.46	101.64	101.13	100.46	99.66	98.17	94.69	92.39	91.85	93.48
RCDPRQ	COM. DEMAND / COM. RDP......	3.61	3.59	3.62	3.64	3.67	3.73	3.76	3.77	3.78	3.80
RIDPRQ	IND. DEMAND / IND. RDP......	20.16	20.18	20.23	20.25	20.27	20.52	20.56	20.64	20.82	21.24
RSDPCQ	SECONDARY DEMAND / POP (GJ).	202.01	210.43	211.60	212.96	217.08	226.58	239.77	259.95	283.41	344.27
RSDPRQ	" " / RDP/.......	15.66	15.71	15.58	15.54	15.45	15.44	15.25	15.27	15.42	15.91
REUPCQ	END-USE DEMAND / POP (GJ)...	216.51	228.67	230.56	232.17	236.66	247.06	260.84	282.19	306.85	369.99
REUPRQ	" " / RDP........	16.78	17.07	16.97	16.94	16.84	16.84	16.59	16.58	16.69	17.10
RPDPCQ	PRIMARY DEMAND / POP (GJ)...	366.93	372.94	395.83	396.78	393.59	417.18	456.39	509.13	565.52	707.88
RPDPRQ	" " / RDP........	28.44	27.84	29.14	28.95	28.01	28.43	29.03	29.91	30.76	32.71

TABLE B.9.4: SUMMARY RESULTS - ENERGY DEMAND REGION: ONTARIO
(PETAJOULES)

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
HTSSDO	SECONDARY DEMAND BY FUEL:	2214.4	2344.5	2392.5	2438.1	2523.7	2807.5	3130.9	3471.6	3844.5	4769.8
HRPSDO	RPP'S	775.7	807.5	816.6	822.6	836.1	893.5	951.2	1038.9	1148.2	1418.8
HNGSDO	NATURAL GAS	682.3	740.9	763.9	788.1	826.1	932.8	1033.6	1146.3	1275.4	1594.9
HELSDO	ELECTRICITY	444.8	471.8	485.7	500.0	523.0	614.5	740.9	839.8	931.9	1169.8
HCCSDO	COAL	22.0	21.5	21.4	21.5	23.1	26.0	30.9	35.9	41.5	55.3
HLPSDO	LPG'S	29.2	25.6	26.5	26.9	27.5	31.9	34.1	35.4	36.9	40.9
HKGSDO	COKE AND COKE OVEN GAS	163.9	171.4	172.5	172.6	177.1	189.0	206.8	227.0	247.0	290.8
HSTSDO	STEAM	25.8	32.4	32.3	32.4	34.9	39.2	46.5	54.2	62.5	83.3
HOFSDO	OTHER	70.6	73.1	73.5	73.9	75.8	80.5	86.9	94.2	101.1	115.9
	PRIMARY DEMAND BY SECTOR:										
HTSPDO	TOTAL	3427.9	3677.1	3735.2	3835.2	4011.8	4540.1	5035.6	5623.1	6240.0	7753.7
HTSEUO	END-USE DEMAND	2464.0	2609.3	2659.8	2707.5	2799.0	3103.8	3457.6	3834.3	4237.6	5224.5
HTSSDO	SECONDARY DEMAND	2214.4	2344.5	2392.5	2438.1	2523.7	2807.5	3130.9	3471.6	3844.5	4769.8
HTSRAO	RESIDENTIAL	461.9	487.0	497.1	506.4	516.2	548.4	571.8	581.7	602.9	676.1
HTSCPO	COMMERCIAL	299.0	315.0	327.1	336.6	348.2	397.0	457.9	522.3	578.3	707.1
HTSINO	INDUSTRIAL	842.0	902.7	918.9	936.8	982.1	1123.2	1304.4	1503.3	1714.0	2224.4
HTSTRO	TRANSPORTATION	611.9	639.9	649.4	658.3	677.2	738.9	796.9	864.2	949.3	1162.2
HTSNEO	NON-ENERGY USE	249.6	264.8	267.3	269.4	275.3	296.4	326.7	362.7	393.1	454.7
HELIRO	INTER-REG'L ELEC. TRANSFERS	-73.3	-29.0	-66.0	-48.2	-11.7	-5.3	-140.8	-144.2	-143.9	-149.9
HTSPCO	PRODUCER CONSUMPTION	162.2	171.0	176.2	181.0	186.8	217.7	250.3	274.0	298.1	359.2
HTSCLO	INTERMEDIATE CONVERSION LOSS	874.9	925.9	965.2	994.9	1037.7	1223.9	1468.5	1658.9	1848.2	2319.9
HTSPDO	PRIMARY DEMAND BY FUEL - TOTAL	3427.9	3677.1	3735.2	3835.2	4011.8	4540.1	5035.6	5623.1	6240.0	7753.7
HRPPDO	RPP'S	1038.3	1057.7	1074.9	1083.5	1102.4	1265.5	1450.8	1569.0	1689.7	2005.2
HNGPDO	NATURAL GAS	781.2	869.2	903.8	931.5	973.8	1176.0	1298.7	1432.7	1576.0	1922.6
HLPPDO	LPG'S	58.7	58.4	59.2	59.6	61.1	68.6	74.7	80.3	86.4	101.2
HCCPDO	COAL	520.1	557.5	515.5	511.8	558.5	577.3	747.5	887.0	856.2	985.7
HENPDO	NUCLEAR ELECTRICITY	662.7	712.1	779.7	845.3	910.4	1040.9	1044.0	1159.2	1528.6	2222.8
HEHPDO	HYDRO ELECTRICITY	296.3	349.2	326.9	327.2	327.3	328.2	329.7	397.6	398.8	397.1
HOFPDO	OTHER (RENEWABLES)	70.6	73.1	75.2	76.2	78.3	83.6	90.1	97.3	104.3	119.1
	ELECTRICITY CONVERTED AT 3.6:										
HTSP20	PRIMARY DEMAND - TOTAL	2797.7	2979.7	3008.0	3064.8	3198.4	3640.5	4132.8	4600.1	4973.5	6032.0
HEHP20	HYDRO ELECTRICITY	101.6	119.7	112.1	112.2	112.2	112.5	113.0	136.3	136.7	136.2
HENP20	NUCLEAR ELECTRICITY	227.2	244.1	267.3	289.8	312.1	356.9	357.9	397.4	524.1	762.1
	RATIOS:										
RRDPHO	RES. DEMAND / HOUSEHOLD (GJ)	129.69	134.15	134.02	134.21	134.20	134.52	131.09	124.20	119.97	117.00
RCDPRO	COM. DEMAND / COM. RDP	3.51	3.54	3.59	3.64	3.68	3.79	3.84	3.86	3.87	3.88
RIDPRO	IND. DEMAND / IND. RDP	16.48	16.48	16.62	16.73	16.71	16.97	16.90	16.62	16.45	16.28
RSDPCO	SECONDARY DEMAND / POP (GJ)	238.97	248.85	250.16	251.35	256.79	272.65	288.90	306.87	327.41	382.66
RSDPRO	" " / RDP/	14.86	14.97	14.94	14.98	14.87	14.82	14.29	13.61	13.17	12.58
REUPCO	END-USE DEMAND / POP (GJ)	265.91	276.95	278.12	279.12	284.80	301.43	319.04	338.93	360.89	419.14
REUPRO	" " / RDP	16.54	16.66	16.61	16.63	16.49	16.38	15.78	15.03	14.52	13.78
RPDPCO	PRIMARY DEMAND / POP (GJ)	369.92	390.30	390.56	395.39	408.21	440.92	464.64	497.05	531.42	622.05
RPDPRO	" " / RDP	23.01	23.48	23.33	23.56	23.63	23.97	22.98	22.04	21.38	20.46

TABLE B.9.5: SUMMARY RESULTS - ENERGY DEMAND REGION: MANITOBA
(PETAJOULES)

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDM	SECONDARY DEMAND BY FUEL:	202.5	211.0	217.6	221.8	226.5	242.5	259.2	277.6	297.7	348.0
HRPSDM	RPP'S	95.8	98.9	101.1	102.8	105.5	113.7	121.2	129.4	138.9	162.2
HNGSDM	NATURAL GAS	51.3	56.2	58.1	59.2	60.0	62.5	63.0	63.6	65.6	72.0
HELSDM	ELECTRICITY	49.3	51.2	53.7	55.2	56.4	61.5	69.9	79.1	87.0	106.4
HCCSDM	COAL	2.5	2.2	2.2	2.1	2.0	1.8	1.8	2.0	2.2	2.7
HLPSDM	LPG'S	2.9	2.0	1.8	2.0	2.0	2.2	2.4	2.7	3.0	3.6
HKGSDM	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
HSTSDM	STEAM	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.5
HOFSDM	OTHER	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5
	PRIMARY DEMAND BY SECTOR:										
HTSPDM	TOTAL	356.7	378.4	387.8	396.6	407.1	442.6	482.8	529.6	570.5	681.2
HTSEUM	END-USE DEMAND	214.4	223.1	230.0	234.8	239.9	256.7	273.8	292.8	313.4	365.1
HTSSDM	SECONDARY DEMAND	202.5	211.0	217.6	221.8	226.5	242.5	259.2	277.6	297.7	348.0
HTSRAM	RESIDENTIAL	54.6	62.0	63.7	65.2	66.3	70.0	72.8	76.0	80.0	91.3
HTSCPM	COMMERCIAL	40.5	40.6	42.4	43.7	44.9	49.3	53.7	57.7	60.8	67.1
HTSINM	INDUSTRIAL	33.4	35.4	37.1	37.3	37.5	38.6	42.6	48.1	54.2	68.7
HTSTRM	TRANSPORTATION	74.0	73.1	74.3	75.6	77.8	84.5	90.1	95.9	102.8	120.9
HTSNEM	NON-ENERGY USE	11.9	12.0	12.5	12.9	13.4	14.3	14.6	15.1	15.8	17.1
HELIRM	INTER-REG'L ELEC. TRANSFERS	11.5	8.2	4.4	3.5	5.0	6.3	5.4	8.7	8.5	14.4
HTSPCM	PRODUCER CONSUMPTION	20.1	26.6	27.9	29.4	30.4	35.7	40.3	43.6	46.8	54.6
HTSCLM	INTERMEDIATE CONVERSION LOSS	110.7	120.5	125.5	128.9	131.7	143.8	163.3	184.5	201.8	247.1
HTSPDM	PRIMARY DEMAND BY FUEL - TOTAL	356.7	378.4	387.8	396.6	407.1	442.6	482.8	529.6	570.5	681.2
HRPPDM	RPP'S	101.1	104.4	107.5	109.6	112.9	121.9	129.8	138.5	148.6	173.2
HNGPDM	NATURAL GAS	70.9	79.5	82.1	84.5	86.1	92.8	96.2	98.2	101.9	112.2
HLPPDM	LPG'S	2.9	2.0	1.9	2.1	2.1	2.3	2.5	2.8	3.1	3.8
HCCPDM	COAL	9.7	13.9	8.4	8.3	8.3	8.2	8.3	8.5	3.0	3.5
HENPDM	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	46.2
HEHPDM	HYDRO ELECTRICITY	171.8	177.9	187.2	191.4	197.2	216.8	245.3	280.9	313.2	341.5
HOFPDM	OTHER (RENEWABLES)	0.3	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2M	PRIMARY DEMAND - TOTAL	243.8	261.5	264.8	270.8	277.5	300.1	321.6	345.0	364.7	426.4
HEHP2M	HYDRO ELECTRICITY	58.9	61.0	64.2	65.6	67.6	74.3	84.1	96.3	107.4	117.1
HENP2M	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.9
	RATIOS:										
RRDPHM	RES. DEMAND / HOUSEHOLD (GJ)	108.08	121.65	122.00	122.43	122.30	123.49	122.88	121.69	120.82	122.77
RCDPRM	COM. DEMAND / COM. RDP	4.64	4.69	4.80	4.90	4.99	5.22	5.36	5.41	5.45	5.48
RIDPRM	IND. DEMAND / IND. RDP	10.19	10.36	10.16	10.00	9.86	9.50	9.35	9.37	9.44	9.73
RSDPCM	SECONDARY DEMAND / POP (GJ)	187.89	194.13	198.62	201.01	203.81	212.65	221.19	230.89	241.13	268.50
RSDPRM	" " / RDP/	13.60	13.88	13.84	13.83	13.65	13.54	13.04	12.50	12.10	11.62
REUPCM	END-USE DEMAND / POP (GJ)	198.91	205.21	210.01	212.72	215.87	225.16	233.65	243.48	253.90	281.67
REUPRM	" " / RDP	14.40	14.68	14.63	14.63	14.46	14.33	13.77	13.18	12.74	12.19
RPDPCM	PRIMARY DEMAND / POP (GJ)	330.87	348.12	354.04	359.33	366.27	388.11	411.91	440.40	462.14	525.56
RPDPRM	" " / RDP	23.95	24.90	24.66	24.72	24.54	24.71	24.28	23.84	23.20	22.75

TABLE B.9.6: SUMMARY RESULTS - ENERGY DEMAND
(PETAJOULES)

REGION: SASKATCHEWAN

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDS	SECONDARY DEMAND BY FUEL:	268.9	274.7	277.5	279.0	284.0	302.4	330.7	363.5	396.8	473.1
HRPSDS	RPP'S	122.3	118.8	119.5	119.7	121.6	129.2	142.2	157.4	172.7	206.6
HNGSDS	NATURAL GAS	87.4	95.9	97.7	98.8	100.6	105.1	108.4	114.1	122.9	146.8
HELSDS	ELECTRICITY	39.9	43.6	43.6	43.4	44.1	48.4	58.1	67.3	73.9	86.6
HCCSDS	COAL	4.8	4.0	4.3	4.6	5.0	6.2	7.5	9.0	10.5	13.8
HLPSDS	LPG'S	3.6	1.1	1.1	1.0	1.1	1.1	1.2	1.3	1.5	1.7
HKGSDS	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDS	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDS	OTHER	10.9	11.2	11.4	11.4	11.7	12.3	13.2	14.3	15.4	17.6
	PRIMARY DEMAND BY SECTOR:										
HTSPDS	TOTAL	416.4	437.2	442.0	446.1	455.3	495.1	558.6	619.9	676.5	792.7
HTSEUS	END-USE DEMAND	280.3	287.2	290.8	292.7	298.2	317.7	346.3	381.3	416.4	496.6
HTSSDS	SECONDARY DEMAND	268.9	274.7	277.5	279.0	284.0	302.4	330.7	363.5	396.8	473.1
HTSRAS	RESIDENTIAL	85.5	92.1	92.8	93.5	94.6	97.5	99.8	102.3	106.0	115.5
HTSCPS	COMMERCIAL	40.1	38.8	39.2	39.3	39.5	41.2	43.7	46.8	49.4	55.3
HTSINS	INDUSTRIAL	69.8	73.0	75.2	76.5	79.9	90.2	104.7	122.6	140.6	182.0
HTSTRS	TRANSPORTATION	73.6	70.7	70.4	69.7	70.0	73.5	82.5	91.9	100.8	120.3
HTSNES	NON-ENERGY USE	11.4	12.5	13.3	13.8	14.3	15.4	16.3	17.8	19.6	23.5
HELIRS	INTER-REG'L ELEC. TRANSFERS	-0.4	-2.7	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
HTSPCS	PRODUCER CONSUMPTION	34.2	47.6	48.5	51.1	53.1	62.9	71.3	76.2	81.1	92.4
HTSCLS	INTERMEDIATE CONVERSION LOSS	102.4	105.2	103.7	103.3	105.0	115.5	141.4	163.3	180.1	204.8
HTSPDS	PRIMARY DEMAND BY FUEL - TOTAL	416.4	437.2	442.0	446.1	455.3	495.1	558.6	619.9	676.5	792.7
HRPPDS	RPP'S	139.5	136.5	137.9	138.6	141.1	150.2	164.6	181.9	199.6	238.9
HNGPDS	NATURAL GAS	119.2	141.1	143.9	147.6	152.0	165.7	182.4	196.6	210.1	243.8
HLPPDS	LPG'S	3.7	1.1	1.1	1.1	1.1	1.1	1.2	1.3	1.5	1.7
HCCPDS	COAL	115.3	118.4	112.4	111.9	114.0	130.0	161.3	164.5	190.0	159.6
HENPDS	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	61.3
HEHPDS	HYDRO ELECTRICITY	33.2	27.3	33.6	33.6	33.6	33.8	33.9	58.8	58.0	67.8
HOFPDS	OTHER (RENEWABLES)	10.9	12.8	13.0	13.2	13.5	14.3	15.2	16.3	17.4	19.6
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2S	PRIMARY DEMAND - TOTAL	399.9	419.2	419.9	424.0	433.2	472.8	536.3	581.2	638.4	707.9
HEHP2S	HYDRO ELECTRICITY	11.4	9.4	11.5	11.5	11.5	11.6	11.5	20.2	19.9	23.3
HENP2S	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.0
	RATIOS:										
RRDPHS	RES. DEMAND / HOUSEHOLD (GJ)	144.02	158.44	156.80	155.79	154.75	151.83	147.27	141.28	136.73	130.51
RCDPRS	COM. DEMAND / COM. RDP	5.99	5.85	5.77	5.71	5.67	5.54	5.43	5.37	5.34	5.31
RIDPRS	IND. DEMAND / IND. RDP	19.02	18.70	18.81	18.91	18.97	19.23	19.43	19.42	19.34	19.08
RSDPCS	SECONDARY DEMAND / POP (GJ)	265.57	269.77	271.14	271.00	274.19	284.76	303.39	325.43	346.62	396.02
RSDPRS	" " / RDP/	17.90	18.71	17.69	17.34	17.10	16.99	16.90	16.78	16.66	16.54
REUPCS	END-USE DEMAND / POP (GJ)	276.79	282.04	284.10	284.37	287.96	299.22	318.32	341.39	363.75	415.68
REUPRS	" " / RDP	18.66	19.56	18.54	18.20	17.96	17.85	17.73	17.61	17.48	17.36
RPDPCS	PRIMARY DEMAND / POP (GJ)	411.20	429.39	431.81	433.34	439.59	466.24	512.57	554.93	590.95	663.53
RPDPRS	" " / RDP	27.72	29.77	28.17	27.73	27.41	27.82	28.54	28.62	28.40	27.72

TABLE B.9.7: SUMMARY RESULTS - ENERGY DEMAND REGION: ALBERTA
(PETAJOULES)

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDA	SECONDARY DEMAND BY FUEL:	778.2	844.1	855.4	855.2	868.2	928.7	1007.9	1109.4	1227.4	1534.9
HRPSDA	RPP'S	308.4	326.1	324.9	320.6	323.5	338.5	371.2	415.0	461.9	573.1
HNGSDA	NATURAL GAS	304.8	342.4	350.5	353.6	358.7	383.3	396.9	420.9	457.6	552.9
HELSDA	ELECTRICITY	120.1	125.7	129.6	130.4	134.4	151.5	180.2	209.4	238.9	327.9
HCCSDA	COAL	0.9	1.3	1.3	1.2	1.2	0.9	0.7	0.7	0.7	0.9
HLPSDA	LPG'S	22.5	25.9	26.1	26.5	26.9	29.5	32.1	34.4	37.0	44.4
HKGSDA	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDA	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDA	OTHER	21.3	22.7	23.0	22.9	23.4	25.0	26.8	29.1	31.2	35.8
	PRIMARY DEMAND BY SECTOR:										
HTSPDA	TOTAL	1485.7	1565.3	1606.0	1607.4	1632.2	1784.8	2022.1	2251.2	2510.2	3060.1
HTSEUA	END-USE DEMAND	1128.7	1217.3	1231.2	1231.9	1256.3	1363.3	1530.0	1689.7	1874.9	2214.1
HTSSDA	SECONDARY DEMAND	778.2	844.1	855.4	855.2	868.2	928.7	1007.9	1109.4	1227.4	1534.9
HTSRAA	RESIDENTIAL	182.4	205.9	207.7	210.1	212.9	224.3	230.0	236.4	250.0	292.9
HTSCPA	COMMERCIAL	126.1	133.2	139.8	143.7	144.9	152.8	164.7	178.9	191.8	222.5
HTSINA	INDUSTRIAL	241.6	268.9	273.3	269.1	275.9	303.7	341.7	392.7	451.4	609.6
HTSTRA	TRANSPORTATION	228.9	236.2	234.5	232.3	234.5	247.8	271.5	301.5	334.2	410.0
HTSNEA	NON-ENERGY USE	350.6	373.3	375.8	376.7	388.1	434.6	522.1	580.3	647.5	679.2
HELIRA	INTER-REG'L ELEC. TRANSFERS	1.9	8.9	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
HTSPCA	PRODUCER CONSUMPTION	68.6	73.7	75.1	75.9	77.0	86.0	96.8	106.4	116.7	141.7
HTSCLA	INTERMEDIATE CONVERSION LOSS	286.4	265.3	293.9	293.8	293.2	329.8	389.6	449.3	512.9	698.4
HTSPDA	PRIMARY DEMAND BY FUEL - TOTAL	1485.7	1565.3	1606.0	1607.4	1632.2	1784.8	2022.1	2251.2	2510.2	3060.1
HRPPDA	RPP'S	397.6	419.4	419.9	416.0	420.3	448.3	495.6	549.1	606.7	742.1
HNGPDA	NATURAL GAS	567.5	638.7	715.2	710.3	669.1	721.1	799.4	871.9	933.0	1040.0
HLPPDA	LPG'S	118.5	126.7	126.9	127.2	133.7	160.5	183.2	185.6	238.5	245.9
HCCPDA	COAL	365.4	343.8	296.1	304.7	358.6	399.0	484.2	510.4	510.3	796.8
HENPDA	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDA	HYDRO ELECTRICITY	15.3	14.0	14.9	14.8	14.8	14.3	14.1	86.3	171.3	180.6
HOFPDA	OTHER (RENEWABLES)	21.3	22.7	33.0	34.4	35.8	41.7	45.6	47.9	50.0	54.6
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2A	PRIMARY DEMAND - TOTAL	1475.5	1556.1	1596.2	1597.7	1622.5	1775.5	2012.9	2194.4	2397.4	2941.4
HEHP2A	HYDRO ELECTRICITY	5.2	4.8	5.1	5.1	5.1	4.9	4.8	29.6	58.9	61.9
HENP2A	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHA	RES. DEMAND / HOUSEHOLD (GJ)	171.06	194.16	192.19	190.85	189.10	183.49	171.35	160.17	155.31	155.90
RCDPRA	COM. DEMAND / COM. RDP	6.00	6.08	6.00	5.94	5.88	5.74	5.61	5.54	5.51	5.50
RIDPRA	IND. DEMAND / IND. RDP	13.10	12.92	12.75	12.61	12.47	12.05	11.74	11.52	11.49	11.83
RSDPCA	SECONDARY DEMAND / POP (GJ)	327.19	353.09	354.44	349.86	349.53	347.67	349.42	360.64	377.37	432.49
RSDPRA	" " / RDP/	17.06	17.55	17.38	17.31	16.99	16.80	16.40	16.13	16.09	16.48
REUPCA	END-USE DEMAND / POP (GJ)	474.60	509.24	510.17	503.98	505.80	510.37	530.41	549.28	576.45	623.88
REUPRA	" " / RDP	24.75	25.31	25.02	24.94	24.58	24.67	24.89	24.56	24.57	23.77
RPDPCA	PRIMARY DEMAND / POP (GJ)	624.68	654.80	665.46	657.59	657.15	668.21	701.01	731.78	771.81	862.23
RPDPRA	" " / RDP	32.57	32.55	32.63	32.54	31.93	32.30	32.90	32.72	32.90	32.85

TABLE B.9.8: SUMMARY RESULTS - ENERGY DEMAND
(PETAJOULES)

REGION: B.C.+YK.+N.W.T.

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
HTSSDZ	SECONDARY DEMAND BY FUEL:	834.1	873.1	881.3	890.9	912.4	976.9	1057.3	1161.2	1266.7	1522.2
HRPSDZ	RPP'S........................	308.4	322.6	323.5	318.7	322.9	334.4	353.6	385.5	429.4	530.1
HNGSDZ	NATURAL GAS..................	154.9	168.1	172.0	188.2	195.7	213.7	224.4	238.6	257.9	301.0
HELSDZ	ELECTRICITY..................	170.4	176.6	178.8	175.8	181.3	204.9	238.2	272.5	298.6	368.8
HCCSDZ	COAL.........................	2.6	2.3	2.2	2.2	2.1	2.3	2.5	2.9	3.4	4.4
HLPSDZ	LPG'S........................	12.5	12.8	13.6	14.0	14.5	17.0	19.6	21.4	22.7	25.9
HKGSDZ	COKE AND COKE OVEN GAS......	1.2	1.2	1.2	1.2	1.3	1.3	1.4	1.5	1.7	2.0
HSTSDZ	STEAM........................	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDZ	OTHER........................	184.1	189.4	189.9	190.8	194.6	203.4	217.6	235.6	253.1	290.1
	PRIMARY DEMAND BY SECTOR:										
HTSPDZ	TOTAL........................	1293.0	1331.5	1352.2	1356.3	1391.9	1513.7	1672.4	1869.0	2045.2	2451.9
HTSEUZ	END-USE DEMAND...............	890.1	929.7	938.7	948.8	971.1	1036.8	1118.8	1225.7	1334.4	1597.4
HTSSDZ	SECONDARY DEMAND.........	834.1	873.1	881.3	890.9	912.4	976.9	1057.3	1161.2	1266.7	1522.2
HTSRAZ	RESIDENTIAL...........	112.1	125.0	128.1	131.7	135.6	150.3	158.7	164.8	170.7	188.7
HTSCPZ	COMMERCIAL............	101.5	104.7	108.3	111.3	114.7	128.1	142.9	157.6	169.8	196.4
HTSINZ	INDUSTRIAL............	396.9	409.8	407.8	408.3	417.6	442.5	485.3	544.9	604.5	747.6
HTSTRZ	TRANSPORTATION........	224.4	233.6	237.1	239.6	244.4	255.9	270.5	293.9	321.7	389.5
HTSNEZ	NON-ENERGY USE...........	56.0	56.7	57.4	57.9	58.6	59.9	61.5	64.6	67.7	75.2
HELIRZ	INTER-REG'L ELEC. TRANSFERS.	-2.0	-9.0	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8
HTSPCZ	PRODUCER CONSUMPTION........	62.8	53.0	52.7	53.1	54.6	60.9	67.4	74.5	81.0	93.7
HTSCLZ	INTERMEDIATE CONVERSION LOSS	342.0	357.8	366.6	360.2	372.0	421.8	492.0	574.5	635.5	766.6
HTSPDZ	PRIMARY DEMAND BY FUEL - TOTAL.	1293.0	1331.5	1352.2	1356.3	1391.9	1513.7	1672.4	1869.0	2045.2	2451.9
HRPPDZ	RPP'S........................	363.4	383.9	385.2	380.5	386.0	401.0	422.3	461.1	509.2	621.9
HNGPDZ	NATURAL GAS..................	206.6	216.4	217.1	234.3	242.4	263.6	276.7	317.3	351.9	356.9
HLPPDZ	LPG'S........................	12.9	13.4	14.2	14.6	15.2	17.6	20.3	22.2	23.1	26.4
HCCPDZ	COAL.........................	7.1	3.7	3.6	3.5	3.5	3.7	4.1	44.0	66.3	6.5
HENPDZ	NUCLEAR ELECTRICITY.........	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDZ	HYDRO ELECTRICITY...........	519.1	524.7	532.0	521.3	538.2	610.0	717.0	774.2	827.0	1135.6
HOFPDZ	OTHER (RENEWABLES)..........	184.1	189.4	200.1	202.2	206.6	217.7	232.1	250.2	267.6	304.6
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2Z	PRIMARY DEMAND - TOTAL.........	952.0	986.7	1002.6	1013.8	1038.2	1112.8	1201.3	1360.2	1501.7	1705.7
HEHP2Z	HYDRO ELECTRICITY...........	178.0	179.9	182.4	178.7	184.5	209.2	245.8	265.4	283.5	389.3
HENP2Z	NUCLEAR ELECTRICITY.........	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHZ	RES. DEMAND / HOUSEHOLD (GJ)	92.75	102.37	103.15	104.35	105.40	108.86	105.75	101.21	97.03	92.29
RCDPRZ	COM. DEMAND / COM. RDP......	4.26	4.23	4.30	4.37	4.44	4.60	4.68	4.70	4.71	4.71
RIDPRZ	IND. DEMAND / IND. RDP......	27.93	27.28	26.98	26.78	26.34	25.57	24.51	23.49	22.62	21.33
RSDPCZ	SECONDARY DEMAND / POP (GJ).	277.85	287.22	285.83	284.71	287.10	288.92	292.17	303.52	316.16	353.04
RSDPRZ	" " / RDP/........	18.86	18.79	18.62	18.61	18.45	18.39	18.05	17.86	17.67	17.60
REUPCZ	END-USE DEMAND / POP (GJ)...	296.50	305.86	304.45	303.22	305.55	306.65	309.16	320.39	333.06	370.47
REUPRZ	" " / RDP........	20.13	20.00	19.84	19.82	19.63	19.52	19.10	18.85	18.61	18.46
RPDPCZ	PRIMARY DEMAND / POP (GJ)...	430.71	438.05	438.57	433.46	437.98	447.70	462.14	488.53	510.45	568.65
RPDPRZ	" " / RDP........	29.24	28.65	28.57	28.33	28.14	28.50	28.54	28.74	28.52	28.34

APPENDIX C: ALTERNATIVE CASE TABLES

C.1 Macroeconomic Assumptions
C.2 World and Domestic Crude Oil Prices
C.3 Domestic and Export Natural Gas Prices
C.4 Electricity Price Determination
C.5 Comparative Fuel Price by Sector
C.6 Supply and Demand for Petroleum
C.7 Supply and Demand for Natural Gas and LPGs
C.8 Electricity Supply and Demand
C.9 Summary Results - Energy Demand

TABLE C.1: MACROECONOMIC ASSUMPTIONS REGION: CANADA

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
	REAL DOMESTIC PRODUCT (RDP): (CONSTANT 81$)										
RDPC	RDP - TOTAL	379.24	394.62	404.08	410.15	427.60	472.78	541.71	625.58	713.44	921.09
RDPAGC	- AGRICULTURE	11.48	10.59	11.59	11.88	12.87	13.77	15.49	17.54	19.69	24.72
RDPINC	- INDUSTRIAL	125.26	132.78	135.25	136.71	143.31	161.85	190.79	227.95	267.38	363.02
RDPIRC	- IRON & STEEL (NAT'L)	1.42	1.53	1.56	1.56	1.64	1.85	2.20	2.64	3.10	4.26
RDPCPC	- COMMERCIAL & PUBLIC ADMIN	200.33	208.10	213.70	217.33	222.05	244.76	276.40	312.13	343.28	415.20
RDPAVC	- AVIATION (NAT'L)	2.83	2.96	3.02	3.08	3.24	3.66	4.31	5.16	6.07	8.34
RDPRLC	- RAIL (NAT'L)	3.02	3.17	3.22	3.30	3.46	3.92	4.64	5.57	6.56	9.00
RDPPCC	RDP PER CAPITA	14807.	15244.	15440.	15500.	15962.	16838.	18332.	20279.	22280.	27132.
YPDKC	REAL PERSONAL DISPOSABLE INCOME	268.09	274.80	279.19	281.43	289.19	317.08	356.25	398.70	445.70	553.24
YPDPCC	PERS'L DISP. INCOME PER CAPITA.	10467.	10615.	10668.	10636.	10796.	11292.	12056.	12925.	13919.	16296.
	PRICES AND COSTS: (1981=1.0)										
PWPIUS	U.S. PRODUCER PRICE (1982=100).	102.8	106.9	110.6	113.4	117.7	135.4	163.5	201.1	244.7	362.2
PGDP	GDP DEFLATOR - TOTAL	1.307	1.354	1.401	1.437	1.489	1.711	2.060	2.521	3.053	4.475
PGDPAG	- AGRICULTURAL	1.063	1.091	1.110	1.135	1.180	1.378	1.662	2.046	2.499	3.728
PGDPIN	- INDUSTRIAL	1.296	1.345	1.392	1.427	1.480	1.699	2.030	2.477	2.976	4.322
PGDPCP	- COMMERCIAL	1.357	1.415	1.469	1.511	1.573	1.832	2.229	2.775	3.393	5.071
PCXDE	PERS. CONS. DEFLATOR EX. ENERGY	1.379	1.435	1.481	1.528	1.585	1.830	2.179	2.666	3.244	4.802
CPI	CONSUMER PRICE INDEX	1.382	1.438	1.491	1.531	1.591	1.840	2.218	2.734	3.323	4.919
PFX	EXCH. RATE ($CAN PER UNIT $US).	1.326	1.229	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250
RIPRVB	AVG. YIELD - 10 PROV'L BONDS	10.8	10.6	11.3	10.5	10.0	10.0	10.0	10.0	10.0	10.0
	DEMOGRAPHIC: ('000)										
POPC	TOTAL POPULATION	25613.	25887.	26172.	26461.	26788.	28079.	29549.	30848.	32021.	33949.
HHC	TOTAL HOUSEHOLDS	9556.	9728.	9893.	10092.	10231.	10887.	11676.	12549.	13488.	15582.
RHHSTC	SINGLE / TOTAL HOUSEHOLDS	0.640	0.638	0.637	0.636	0.635	0.633	0.630	0.625	0.619	0.605
	LABOUR MARKET:										
POPLFC	LABOUR FORCE SOURCE POP. ('000)	19825.	20065.	20298.	20525.	20757.	21648.	22717.	23830.	24998.	27508.
LFC	LABOUR FORCE ('000)	13121.	13383.	13584.	13785.	13956.	14662.	15594.	16586.	17457.	19338.
EMPC	TOTAL EMPLOYMENT ('000)	11954.	12342.	12533.	12615.	12854.	13471.	14410.	15607.	16498.	18287.
URATEC	UNEMPLOYMENT RATE (%)	8.89	7.78	7.74	8.49	7.89	8.12	7.60	5.90	5.50	5.44
RDPPEC	LABOUR PRODUCTIVITY (RDP/EMP)	31724.	31974.	32242.	32513.	33265.	35096.	37594.	40082.	43245.	50369.
	PASSENGER VEHICLES:										
NPVSTC	SALES - VOLUME ('000)	1065.1	1073.9	1073.0	1112.4	1188.9	1315.9	1428.4	1546.4	1710.2	2065.4
ENPVS	- EFFICIENCY (L/100KM)	10.9	10.8	10.9	10.9	10.9	10.7	10.4	10.1	10.0	9.9
KTPVSC	STOCK - VOLUME ('000)	9979.0	10181.1	10333.7	10518.2	10767.8	11921.7	13417.4	14809.6	16209.9	19537.6
EKTPVC	- EFFICIENCY (L/100KM)	11.5	11.7	11.5	11.3	11.2	10.9	10.6	10.4	10.1	10.0
KTMAC	MANUFAC'NG CAPITAL STOCK ($81B).	120.759	130.660	133.727	135.541	143.742	166.767	202.720	248.863	297.843	416.624
KGDSC	NATURAL GAS DIST. CAPACITY (MCM)	896.	898.	901.	908.	918.	943.	972.	1002.	1028.	1081.
DDAYSC	HEATING DEGREE DAYS (NORM=1)	0.896	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

TABLE C.2: WORLD AND DOMESTIC CRUDE OIL PRICES
($/CUBIC METRE)

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	WEST TEXAS INTERMEDIATE: ($US)										
PWTCU	CUSHING	120.56	100.53	94.39	94.39	100.31	128.06	173.81	235.73	286.83	424.52
PWTCUR	REAL ($1989)	130.41	104.58	94.39	90.76	92.74	101.21	112.90	125.86	125.87	125.85
TOCUCH	TRANSPORTATION TO CHICAGO	2.83	2.83	2.88	2.92	2.97	3.19	3.51	3.90	4.30	5.24
TRFDU	U.S. REFINERY TAX	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
PWTCH	CHICAGO	123.91	103.88	97.79	97.83	103.80	131.77	177.83	240.14	291.65	430.28
	BRENT ($US)										
PBRNS	NORTH SEA (F.O.B)	115.83	94.18	89.82	89.95	95.90	123.42	168.27	229.00	279.05	414.05
TOLOSS	OCEAN LOSS	0.46	0.38	0.36	0.36	0.38	0.49	0.67	0.92	1.12	1.66
TONSPO	TRANSPORTATION TO PORTLAND	4.68	5.05	5.14	5.20	5.30	5.69	6.26	6.95	7.67	9.35
TOPOMO	TRANSPORTATION TO MONTREAL	4.06	4.66	4.74	4.80	4.89	5.25	5.77	6.41	7.07	8.62
PBRMO	MONTREAL (C.I.F)	125.04	104.27	100.06	100.32	106.47	134.85	180.96	243.27	294.92	433.67
	LANDED IMPORT COST:										
PCRICA	IMPORT MIX ADJUSTMENT	-4.15	-2.51	-3.00	-3.01	-3.19	-4.05	-5.43	-7.30	-8.85	-13.01
PCRMU	AT MONTREAL (CIF) ($US)	120.89	101.76	97.06	97.31	103.28	130.80	175.54	235.98	286.07	420.66
PFX	EXCH. RATE ($CAN PER UNIT $US)	1.326	1.229	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250
PCRMT	AT MONTREAL (CIF) ($CDN)	160.27	125.05	121.32	121.63	129.10	163.50	219.42	294.97	357.58	525.83
	CANADIAN PAR:										
PPACH	CHICAGO ($US)	122.34	102.50	96.81	96.85	102.76	130.45	176.06	237.74	288.73	425.97
TRFPAU	U.S. IMPORT TARIFFS	1.64	1.56	1.39	1.23	1.07	0.74	0.74	0.74	0.74	0.74
TOBOCH	TRANSPORTATION TO U.S. BORDER	2.98	2.97	3.02	3.06	3.12	3.35	3.68	4.09	4.52	5.50
TOBOED	TRANSPORTATION TO EDMONTON	2.29	2.52	2.57	2.60	2.65	2.84	3.12	3.45	3.80	4.61
PPAED	EDMONTON ($CDN)	153.05	117.29	112.29	112.45	119.90	154.40	210.65	286.83	349.59	518.90
	REFINERY CRUDE COST ($CDN):										
PCRATA	ALBERTA	149.25	114.75	107.57	107.72	114.86	147.91	201.79	274.77	334.89	497.08
PCRATO	ONTARIO	152.69	122.47	117.18	115.83	121.58	154.85	208.87	281.95	343.93	507.29
PCRATQ	QUEBEC	156.05	121.83	119.12	117.43	122.84	156.14	210.18	283.24	345.61	509.16
PCRATF	ATLANTIC	154.88	119.33	115.40	115.63	122.99	156.94	212.21	286.96	348.74	515.05

TABLE C.3: DOMESTIC AND EXPORT NATURAL GAS PRICES
($/GIGAJOULE)

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
	DOMESTIC PRICE AT ALTA. BORDER:										
PNGAB	AVERAGE NOMINAL	1.87	1.77	1.88	1.99	2.11	2.82	3.93	5.63	6.88	10.14
PRNGAB	AVERAGE REAL (1981=1.00)	1.43	1.31	1.34	1.38	1.42	1.65	1.91	2.23	2.25	2.27
PNGABR	RESIDENTIAL	2.24	2.10	2.20	2.20	2.35	3.09	4.08	5.85	7.15	10.56
PNGABC	COMMERCIAL	2.14	2.01	2.05	2.11	2.26	2.97	4.00	5.74	7.02	10.37
PNGABI	INDUSTRIAL	1.69	1.61	1.73	1.82	1.92	2.63	3.84	5.51	6.74	9.96
PGDSAB	DIRECT SALES	1.39	1.38	1.38	1.63	1.82	2.54	3.71	5.32	6.50	9.60
PCMPAB	SYSTEM GAS	1.80	1.69	1.85	1.89	1.95	2.66	3.89	5.58	6.83	10.08
GOPAR	TORONTO GAS/OIL PARITY	0.74	0.79	0.88	0.93	0.94	0.94	0.94	0.96	0.96	0.96
	EXPORT PRICE AT US BORDER:										
PNGXT	NOMINAL ($CDN)	2.43	2.19	2.30	2.40	2.52	3.19	4.38	6.18	7.56	11.15
PRNGXT	REAL ($CDN) (1981=1.00)	1.86	1.62	1.64	1.67	1.69	1.86	2.13	2.45	2.48	2.49
PFX	EXCH. RATE ($CAN PER UNIT $US)	1.326	1.229	1.250	1.250	1.250	1.250	1.250	1.250	1.250	1.250
PNGXU	NOMINAL ($US)	1.83	1.77	1.84	1.92	2.02	2.55	3.50	4.95	6.04	8.92

TABLE C.4: ELECTRICITY PRICE DETERMINATION (NOMINAL)

REGION: CANADA

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	UTILITY FUEL INPUT PRICES: ($/GJ)										
PCCUEC	COAL	1.270	1.426	1.367	1.342	1.405	1.896	2.601	3.566	4.369	5.954
PHFUEC	HEAVY FUEL OIL	3.120	2.358	2.251	2.250	2.405	3.667	5.627	7.519	9.078	12.799
PDSUEC	DISTILLATES	7.480	6.297	6.239	6.276	6.643	8.278	10.614	13.424	16.511	23.993
PNGUEC	NATURAL GAS	1.690	1.907	1.777	1.693	1.973	2.675	3.982	6.198	7.411	10.828
PNUUEC	NUCLEAR	0.438	0.485	0.502	0.515	0.533	0.613	0.738	0.903	1.093	1.603
POFUEC	OTHER FUELS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	PLANNED COSTS: ($MILLIONS)										
FPETTC	TOTAL PLANNED COSTS	18058.3	18738.3	19552.5	20343.8	21420.1	27311.3	41918.6	63000.3	85577.4	155951.1
FPEOCC	PLANNED OPERATING COSTS	6605.5	7327.4	7585.1	7814.9	8553.1	11531.3	17712.0	25649.1	33456.2	61425.3
FPFULC	PLANNED FUEL COSTS	1735.6	2007.7	1919.7	1952.3	2204.9	3876.4	6813.7	10506.5	12943.7	23339.7
FIWSAC	WAGES AND SALARIES	2877.9	3217.6	3411.7	3549.9	3796.9	4702.7	6679.2	9411.9	12724.1	23808.5
FPEOOC	OTHER OPERATING COSTS	785.5	875.9	957.1	974.1	1128.8	1230.5	1842.1	2532.9	3491.8	6674.4
FITXSC	INDIRECT TAXES	732.7	755.7	773.7	803.4	843.3	993.9	1343.8	1777.3	2361.1	3912.1
FIROYC	ROYALTIES	473.8	470.4	522.9	535.2	579.2	727.8	1033.1	1420.4	1935.5	3690.7
FIEFXC	FIXED COSTS	8913.1	9290.6	9461.7	9931.8	10292.8	12108.3	18869.1	28894.8	41590.8	82012.8
FIINTC	NET INTEREST COSTS	6728.5	7086.9	7134.4	7491.1	7723.1	8934.1	13951.7	21357.7	30896.7	61352.8
FIDEPC	DEPRECIATION	2184.6	2203.6	2327.3	2440.7	2569.7	3174.1	4917.4	7537.1	10694.1	20660.0
FIRETC	TOTAL RETURN ON NET EQUITY	1656.4	1616.1	1915.3	2136.1	2152.2	3372.4	4193.9	6704.5	8841.1	10883.2
FICRPC	PLANNED CONTRIB'N TO RESERVE	-8.4	-16.9	-30.7	-164.9	-216.9	-403.1	325.6	764.8	508.5	-80.3
FPFEXC	PLANNED EXCHANGE LOSS	379.3	-10.7	70.8	61.6	53.6	30.7	15.3	7.6	3.8	0.9
FIITXC	INCOME TAX	317.9	329.9	341.4	350.1	363.1	416.8	498.0	607.7	730.2	1060.2
FIEOXC	OTHER EXPENSES	194.5	201.9	208.9	214.2	222.2	255.0	304.7	371.9	446.8	648.8
	OTHER REVENUE FLOWS: ($MILLION)										
FISAXC	FROM NET EXTERNAL SALES	1481.7	920.1	1045.8	986.4	969.9	1441.5	2292.6	2932.2	3668.6	4499.3
FMRESC	EXTERNAL SALES	1741.7	1160.4	1522.7	1428.3	1203.6	1635.6	3252.8	4194.2	5208.9	6463.4
FMCEPC	EXTERNAL PURCHASES	260.0	240.2	476.9	441.9	233.8	194.1	960.1	1262.0	1540.3	1964.2
FISUBC	SUBSIDIES	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
FIROTC	OTHER OPERATING REVENUE	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4
FIOTIC	OTHER INCOME	699.2	725.8	751.1	770.1	798.7	916.8	1095.5	1336.9	1606.3	2332.3
FMRRQC	PLANNED DOMESTIC REVENUE REQUIREMENTS ($MILLIONS)	15424.0	16639.0	17302.3	18134.0	19198.2	24499.6	38077.2	58278.0	79849.3	148666.2
VEUIPC	PLANNED INTERNAL SALES (GHW)	367444.	381694.	393169.	398918.	414409.	472127.	569303.	663143.	761301.	1021722.
	AVERAGE PRICES: (CENTS/KWH)										
PELCAC	BASED ON REVENUE REQUIREMENTS	4.327	4.480	4.426	4.572	4.682	5.476	7.091	9.057	10.685	14.773
PELAAC	ANNOUNCED PRICES	4.327	4.548	4.644	4.678	4.755	5.227	6.535	8.452	10.239	14.170
PELFAC	FORECAST PRICES	4.327	4.548	4.664	4.737	4.873	5.384	6.868	8.911	10.621	14.759

TABLE C.5: ENERGY PRICES - THERMAL UNITS REGION: CANADA
($/GIGAJOULE)

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
	ENERGY PRICE INDEXES (1981=1.0)										
PDIRAC	RESIDENTIAL..................	1.41	1.47	1.53	1.56	1.62	1.84	2.32	3.05	3.71	5.28
PDICPC	COMMERCIAL...................	1.47	1.50	1.56	1.58	1.64	1.82	2.30	3.04	3.70	5.27
PDIINC	INDUSTRIAL...................	1.36	1.35	1.39	1.40	1.45	1.66	2.14	2.83	3.46	4.90
PDITRC	TRANSPORTATION...............	1.31	1.32	1.37	1.42	1.45	1.74	2.18	2.79	3.39	5.01
PDISDC	TOTAL SECONDARY DEMAND......	1.37	1.39	1.44	1.47	1.52	1.75	2.22	2.90	3.54	5.08
	REGIONAL SECTORAL PRICES: ($/GJ - EFFICIENCY ADJUSTED)										
PULFRC	LFO - RESIDENTIAL..............	11.41	12.18	12.26	12.41	12.97	15.61	19.79	25.48	31.04	45.97
PULFCC	- COMMERCIAL...............	9.14	9.68	9.75	9.88	10.34	12.47	15.82	20.37	24.81	36.72
PUHFIC	HFO - INDUSTRIAL...............	3.61	2.90	2.77	2.76	2.92	3.81	5.26	7.23	8.82	13.03
PUHFCC	- COMMERCIAL...............	3.87	3.19	3.05	3.00	3.17	4.12	5.67	7.78	9.49	14.01
PUNGRC	NATURAL GAS - RESIDENTIAL......	7.59	7.50	7.87	7.99	8.40	10.27	12.93	17.23	20.98	30.83
PUNGCC	- COMMERCIAL.......	5.43	5.40	5.56	5.70	6.02	7.39	9.48	12.74	15.56	23.04
PUNGIC	- INDUSTRIAL.......	3.97	3.64	3.46	3.32	3.43	4.48	6.19	8.54	10.43	15.39
PUELRC	ELECTRICITY - RESIDENTIAL......	13.02	14.02	14.62	14.90	15.38	16.74	21.03	27.65	33.66	46.84
PUELCC	- COMMERCIAL.......	16.46	17.10	17.81	18.07	18.55	20.00	25.01	33.16	40.31	56.54
PUELIC	- INDUSTRIAL.......	9.41	9.72	10.14	10.36	10.70	11.64	14.64	19.05	23.25	32.33
	PRICE RATIOS: (EFFICIENCY ADJ'D)										
	RESIDENTIAL:										
RPEORC	ELECTRICITY / LIGHT FUEL OIL	1.14	1.15	1.19	1.20	1.19	1.07	1.06	1.09	1.08	1.02
RPEGRC	ELECTRICITY / NATURAL GAS...	1.72	1.87	1.86	1.86	1.83	1.63	1.63	1.61	1.60	1.52
RPOGRC	LIGHT FUEL OIL / NATURAL GAS	1.50	1.62	1.56	1.55	1.54	1.52	1.53	1.48	1.48	1.49
	COMMERCIAL:										
RPEOCC	ELECTRICITY / LIGHT FUEL OIL	1.80	1.77	1.83	1.83	1.79	1.60	1.58	1.63	1.62	1.54
RPEGCC	ELECTRICITY / NATURAL GAS...	3.03	3.17	3.20	3.17	3.08	2.71	2.64	2.60	2.59	2.45
RPOGCC	LIGHT FUEL OIL / NATURAL GAS	1.68	1.79	1.75	1.73	1.72	1.69	1.67	1.60	1.59	1.59
	INDUSTRIAL:										
RPEOIC	ELECTRICITY / HEAVY FUEL OIL	2.61	3.35	3.66	3.76	3.67	3.06	2.78	2.64	2.64	2.48
RPEGIC	ELECTRICITY / NATURAL GAS...	2.37	2.67	2.93	3.12	3.12	2.60	2.37	2.23	2.23	2.10
RPOGIC	HEAVY FUEL OIL / NATURAL GAS	0.91	0.80	0.80	0.83	0.85	0.85	0.85	0.85	0.85	0.85

TABLE C.6: SUPPLY AND DEMAND - PETROLEUM
(THOUSANDS OF CUBIC METRES PER DAY)

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	DOMESTIC CRUDE OIL PRODUCTION:										
VCRPN	TOTAL	261.6	273.5	274.0	274.0	272.0	241.7	230.2	238.0	240.0	249.1
QCROO	- CONVENTIONAL OLD OIL	77.6	69.7	59.6	54.5	46.1	27.6	16.6	9.9	6.3	2.7
QSOPN	- SYNTHETIC OIL	28.7	31.7	33.5	33.5	33.5	34.9	36.3	47.3	47.3	47.3
QCRER	- ENHANCED RECOVERY	17.4	18.4	18.2	18.7	19.2	19.5	20.9	23.2	22.9	17.8
QCRNT	- NEW OIL	137.9	153.7	162.7	167.3	173.2	160.7	157.4	158.6	164.4	182.3
QCRUN	- NET HEAVY UPGRADING	0.0	0.0	0.0	0.0	0.0	-1.0	-1.0	-1.0	-1.0	-1.0
	DOMESTIC CRUDE OIL DEMAND:										
VRPDDC	PETROLEUM PRODUCTS DEMAND	227.6	239.1	242.1	246.6	255.3	288.8	324.3	357.2	389.9	478.8
VCRRG	REFINERY GAIN AND ADJUSTMENTS	13.0	13.2	13.3	13.4	13.6	14.2	14.9	15.6	16.3	18.0
QLPRN	NET REFINERY PROD'N OF LPG'S	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
QLPPR	- TOTAL REFINERY LPG PROD'N	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8	6.8
VLPRP	- REFINERY LPG CONSUMPTION	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6	6.6
VCRDD	DOMESTIC CRUDE OIL DEMAND	214.8	226.1	229.0	233.4	242.0	274.7	309.6	341.8	373.8	460.9
	STOCK CHANGES AND ADJUSTMENTS:										
VRPSC	REFINED PETROLEUM PRODUCTS	3.7	-3.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VCRSC	CRUDE OIL	3.4	-2.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PETROLEUM EXPORTS:										
VPEXT	TOTAL	125.7	149.6	140.4	142.4	131.4	80.5	61.8	59.9	69.0	85.1
VCRXT	- CRUDE OIL - TOTAL	98.7	112.8	102.4	102.4	93.4	45.5	36.8	39.9	49.0	65.1
VLMXS	- LIGHT & MEDIUM	41.9	49.9	45.0	45.0	35.0	5.0	0.0	0.0	0.0	0.0
VHVXS	- HEAVY (INCL. DILUENT)	56.8	62.9	57.4	57.4	58.4	40.5	36.8	39.9	49.0	65.1
VCRXE	- EXCHANGES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VRPXT	- PRODUCTS - TOTAL	27.0	36.8	38.0	40.0	38.0	35.0	25.0	20.0	20.0	20.0
	PETROLEUM IMPORTS:										
VPEMT	TOTAL	86.0	96.6	95.3	101.8	101.3	113.5	141.2	163.7	202.9	297.0
VCRMT	- CRUDE OIL	64.0	72.3	70.3	76.8	76.3	88.5	111.2	123.7	152.9	237.0
VRPMT	- PRODUCTS - TOTAL	22.0	24.3	25.0	25.0	25.0	25.0	30.0	40.0	50.0	60.0
VPEMN	NET PETROLEUM IMPORTS	-39.7	-53.0	-45.0	-40.6	-30.0	33.0	79.4	103.8	133.9	211.8

TABLE C.7: SUPPLY & DEMAND - NATURAL GAS & NGLS

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
	MARKETABLE NATURAL GAS: (MCM)										
VNGPN	TOTAL PRODUCTION	79252.	92095.	93073.	97019.	99454.	115432.	127506.	137434.	146234.	166937.
VNGDD	DOMESTIC DEMAND	51246.	56774.	59741.	60954.	61789.	70967.	80207.	90135.	98935.	119638.
VNGSC	STOCK CHANGE	-83.	0.	0.	0.	0.	0.	0.	0.	0.	0.
VNGXT	EXPORTS	28023.	35900.	34002.	36835.	38535.	45336.	48169.	48169.	48169.	48169.
VNGMT	IMPORTS	93.	309.	400.	500.	600.	600.	600.	600.	600.	600.
VNGAJ	STATISTICAL ADJUSTMENT	-160.	270.	270.	270.	270.	270.	270.	270.	270.	270.
	GAS PLANT NGLS (KCM/D)										
QLPRN	NET REFINERY PRODUCTION	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
VGPPN	GAS PLANT PROD (INCL SOLV FLD	56.11	60.35	62.27	63.81	64.54	68.47	72.06	73.88	76.66	81.88
VPBPN	PROPANE & BUTANE	21.47	22.60	22.37	22.49	22.43	22.91	23.61	24.74	25.74	28.09
VETPN	ETHANE	8.93	10.06	9.99	10.23	10.31	11.27	12.15	13.14	14.02	16.09
QPBRS	FROM REPROCESSING PLANTS	25.70	27.70	29.90	31.10	31.80	34.30	36.30	36.00	36.90	37.70
VGPDD	DOMESTIC DEMAND	25.77	27.92	27.85	27.96	29.00	34.32	37.90	38.55	46.37	50.34
VGPER	REQUIREMENTS FOR EOR PROJECTS	15.50	19.30	18.90	17.70	13.00	2.50	0.40	0.00	0.00	0.00
VGPSC	STOCK CHANGE	2.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VGPAJ	STATISTICAL ADJUSTMENT	-0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VGPXT	NET EXPORTS (POTENTIAL)	12.47	13.33	15.72	18.36	22.74	31.85	33.96	35.53	30.49	31.74

TABLE C.8: ELECTRICITY SUPPLY & DEMAND (GIGAWATT HOURS)

REGION: CANADA

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
	GENERATING CAPACITY (MEGAWATTS).										
KEGCTC	TOTAL	100705.	109071.	111275.	112856.	115956.	124230.	146445.	166852.	186677.	237978.
KEGCUC	UTILITIES	94461.	101806.	103989.	105457.	108534.	116543.	138698.	159105.	178930.	230231.
KEGCIC	INDUSTRIES	6244.	7265.	7286.	7399.	7422.	7687.	7747.	7747.	7747.	7747.
	CANGEN PLANNED GENERATION:										
	TOTAL:										
VEUPXC	UTILITIES	446916.	446050.	467001.	473208.	490528.	555551.	663371.	765786.	873475.	1142489.
VEIPXC	INDUSTRY	36725.	38278.	40974.	41609.	41859.	50492.	51275.	51275.	51275.	51275.
	FOR DOMESTIC DEMAND:										
VELDXC	TOTAL	439668.	456604.	470745.	479652.	497748.	567713.	667746.	773582.	879532.	1157189.
	CANGEN PLANNED CAPACITY FACTOR:										
RGCUPC	UTILITIES	0.540	0.500	0.513	0.512	0.516	0.544	0.546	0.549	0.557	0.566
RGCIPC	INDUSTRY	0.671	0.601	0.642	0.642	0.644	0.750	0.756	0.756	0.756	0.756
	EXTERNAL SALES & PURCHASES:										
VELENC	NET EXTERNAL SALES	43956.	27724.	37230.	35165.	34639.	38330.	46901.	43480.	45219.	36576.
VELXNC	NET EXPORTS TO U.S.	43956.	27724.	37230.	35165.	34639.	38330.	46901.	43480.	45219.	36576.
VELESC	EXTERNAL SALES	47427.	34030.	39710.	37645.	37119.	41522.	50093.	46672.	48411.	38668.
VELXTC	EXPORTS	47427.	34030.	39710.	37645.	37119.	41522.	50093.	46672.	48411.	38668.
VELEPC	EXTERNAL PURCHASES	3471.	6306.	2480.	2480.	2480.	3192.	3192.	3192.	3192.	2092.
VELMTC	IMPORTS	3471.	6306.	2480.	2480.	2480.	3192.	3192.	3192.	3192.	2092.
VELIRC	NET INTER-REGIONAL TRANSFERS	0.	-2.	0.	0.	0.	0.	0.	1.	0.	0.
	GENERATION FOR DOMESTIC DEMAND: (INC. OWN-USE)										
VELDDC	TOTAL	439668.	457751.	469963.	477983.	496448.	566857.	670608.	778993.	883667.	1169048.
VEUDDC	UTILITIES	402943.	419473.	428989.	436374.	454589.	516365.	619332.	727718.	832391.	1117772.
VEIDDC	INDUSTRY	36725.	38278.	40974.	41609.	41859.	50492.	51275.	51275.	51275.	51275.
	TOTAL GENERATION:										
VELPNC	TOTAL	483641.	485473.	507193.	513148.	531087.	605187.	717509.	822474.	928886.	1205624.
VEUPNC	UTILITIES	446916.	447195.	466219.	471539.	489228.	554695.	666233.	771199.	877610.	1154348.
VEIPNC	INDUSTRY	36725.	38278.	40974.	41609.	41859.	50492.	51275.	51275.	51275.	51275.
	CAPACITY FACTOR:										
RGCUAC	UTILITIES	0.540	0.501	0.512	0.510	0.515	0.543	0.548	0.553	0.560	0.572
RGCIAC	INDUSTRY	0.671	0.601	0.642	0.642	0.644	0.750	0.756	0.756	0.756	0.756

TABLE C.9.1: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES)

REGION: CANADA

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDC	SECONDARY DEMAND BY FUEL:	6098.1	6429.1	6562.7	6672.6	6898.3	7656.7	8647.0	9711.9	10840.3	13753.4
HRPSDC	RPP'S	2432.5	2544.9	2600.5	2635.9	2711.5	2969.6	3293.6	3654.2	4053.8	5064.4
HNGSDC	NATURAL GAS	1470.1	1598.2	1631.9	1677.6	1746.0	1956.7	2201.9	2461.4	2747.6	3481.9
HELSDC	ELECTRICITY	1452.2	1511.1	1551.9	1578.3	1639.2	1872.9	2215.3	2572.0	2915.9	3853.9
HCCSDC	COAL	49.7	51.8	50.3	49.1	50.5	53.1	61.3	72.4	84.6	116.3
HLPSDC	LPG'S	85.6	89.9	88.6	89.5	91.3	100.6	102.1	98.5	104.7	123.5
HKGSDC	COKE AND COKE OVEN GAS	173.5	181.2	183.0	183.0	188.3	202.4	223.9	248.7	273.6	329.3
HSTSDC	STEAM	27.6	33.0	33.0	33.2	35.9	41.5	50.9	60.7	71.0	98.3
HOFSDC	OTHER	406.8	419.0	423.5	426.0	435.6	460.0	498.0	544.1	589.1	685.8
	PRIMARY DEMAND BY SECTOR:										
HTSPDC	TOTAL	10385.6	10961.4	11225.5	11418.6	11810.1	13235.5	15162.0	17190.4	19250.1	24504.4
HTSEUC	END-USE DEMAND	6895.4	7292.7	7443.3	7564.4	7816.2	8665.4	9794.7	10977.5	12230.5	15297.0
HTSSDC	SECONDARY DEMAND	6098.1	6429.1	6562.7	6672.6	6898.3	7656.7	8647.0	9711.9	10840.3	13753.4
HTSRAC	RESIDENTIAL	1239.8	1330.2	1354.1	1377.8	1407.4	1509.9	1606.1	1670.2	1748.0	2008.9
HTSCPC	COMMERCIAL	848.3	880.5	912.9	935.9	962.3	1077.0	1225.1	1382.8	1519.3	1835.7
HTSINC	INDUSTRIAL	2285.6	2423.1	2468.3	2500.5	2610.3	2951.6	3454.9	4057.5	4701.3	6344.4
HTSTRC	TRANSPORTATION	1726.9	1795.2	1827.4	1858.3	1918.3	2118.2	2360.9	2601.4	2871.7	3564.4
HTSNEC	NON-ENERGY USE	797.4	863.6	880.7	891.8	917.9	1008.6	1147.7	1265.6	1390.1	1543.6
HELIRC	INTER-REG'L ELEC. TRANSFERS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HTSPCC	PRODUCER CONSUMPTION	470.1	511.8	521.7	537.0	557.2	640.7	730.7	816.9	902.0	1126.1
HTSCLC	INTERMEDIATE CONVERSION LOSS	3020.0	3157.0	3260.5	3317.3	3436.6	3929.4	4636.6	5396.1	6117.7	8081.2
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL	10385.6	10961.4	11225.5	11418.6	11810.1	13235.5	15162.0	17190.4	19250.1	24504.4
HRPPDC	RPP'S	3112.2	3287.1	3317.8	3384.0	3508.3	3983.5	4481.1	4940.3	5391.9	6629.4
HNGPDC	NATURAL GAS	1938.1	2147.2	2259.4	2305.3	2336.8	2684.0	3033.4	3408.9	3741.7	4524.7
HLPPDC	LPG'S	214.2	232.7	231.5	232.3	241.1	285.2	315.0	320.4	385.4	418.4
HCCPDC	COAL	1127.3	1152.8	1056.8	1057.7	1167.8	1352.1	1696.7	1952.2	1942.2	2491.5
HENPDC	NUCLEAR ELECTRICITY	765.3	824.7	885.2	949.8	1015.8	1149.5	1184.8	1406.6	1889.3	3736.3
HEHPDC	HYDRO ELECTRICITY	2826.9	2891.2	3022.5	3031.3	3070.7	3279.5	3908.9	4573.8	5266.5	5974.3
HOFPDC	OTHER (RENEWABLES)	406.8	425.7	452.3	458.1	469.6	501.7	542.1	588.2	633.1	729.9
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2C	PRIMARY DEMAND - TOTAL	8030.3	8519.5	8657.6	8802.5	9124.7	10325.0	11814.8	13260.4	14547.7	18123.2
HEHP2C	HYDRO ELECTRICITY	969.2	991.3	1036.3	1039.3	1052.8	1124.4	1340.2	1568.2	1805.7	2048.3
HENP2C	NUCLEAR ELECTRICITY	262.4	282.8	303.5	325.7	348.3	394.1	406.2	482.3	647.8	1281.0
	RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	118.59	125.77	125.70	125.93	126.13	127.36	126.41	122.11	118.63	117.91
RCDPRC	COM. DEMAND / COM. RDP	4.03	4.03	4.07	4.10	4.13	4.20	4.24	4.24	4.24	4.24
RIDPRC	IND. DEMAND / IND. RDP	18.25	18.25	18.25	18.29	18.21	18.24	18.11	17.80	17.58	17.48
RSDPCC	SECONDARY DEMAND / POP (GJ)	238.09	248.35	250.76	252.17	257.51	272.69	292.63	314.83	338.54	405.12
RSDPRC	" " / RDP/	16.08	16.29	16.24	16.27	16.13	16.20	15.96	15.52	15.19	14.93
REUPCC	END-USE DEMAND / POP (GJ)	269.22	281.71	284.41	285.87	291.78	308.61	331.47	355.86	381.95	450.59
REUPRC	" " / RDP	18.18	18.48	18.42	18.44	18.28	18.33	18.08	17.55	17.14	16.61
RPDPCC	PRIMARY DEMAND / POP (GJ)	405.48	423.43	428.92	431.53	440.87	471.37	513.11	557.26	601.17	721.80
RPDPRC	" " / RDP	27.39	27.78	27.78	27.84	27.62	28.00	27.99	27.48	26.98	26.60

TABLE C.9.2: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES)

REGION: ATLANTIC

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDF	SECONDARY DEMAND BY FUEL:	468.5	485.3	510.1	520.7	534.5	574.2	624.9	681.0	746.5	906.0
HRPSDF	RPP'S	300.8	311.8	325.1	331.7	340.4	364.1	397.3	431.0	463.5	549.4
HNGSDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HELSDF	ELECTRICITY	102.0	105.5	112.9	116.3	120.4	133.0	145.1	161.3	188.0	247.9
HCCSDF	COAL	2.2	3.4	3.5	3.4	3.4	3.1	3.1	3.5	3.9	5.1
HLPSDF	LPG'S	5.4	6.4	6.8	6.9	7.2	8.5	9.5	10.3	11.3	13.8
HKGSDF	COKE AND COKE OVEN GAS	5.9	5.9	6.5	6.6	6.6	6.7	7.1	7.6	8.0	9.0
HSTSDF	STEAM	1.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
HOFSDF	OTHER	51.3	52.1	55.1	55.7	56.3	58.6	62.6	67.1	71.4	80.4
	PRIMARY DEMAND BY SECTOR:										
HTSPDF	TOTAL	988.0	1092.6	1040.6	1071.2	1152.2	1258.7	1476.3	1582.4	1714.0	2035.4
HTSEUF	END-USE DEMAND	491.1	508.6	534.9	546.5	561.0	602.2	654.2	711.9	779.6	943.9
HTSSDF	SECONDARY DEMAND	468.8	485.3	510.1	520.7	534.5	574.2	624.9	681.0	746.5	906.0
HTSRAF	RESIDENTIAL	85.3	89.3	91.4	93.3	95.5	100.1	104.0	109.8	117.9	136.4
HTSCPF	COMMERCIAL	64.1	64.1	66.2	67.6	69.4	76.1	84.3	93.0	100.6	117.2
HTSINF	INDUSTRIAL	164.3	167.7	184.2	187.9	192.1	206.8	229.4	256.6	290.0	368.1
HTSTRF	TRANSPORTATION	155.0	164.2	168.4	172.0	177.6	191.3	207.1	221.6	238.1	284.3
HTSNEF	NON-ENERGY USE	22.4	23.3	24.8	25.8	26.5	27.9	29.3	31.0	33.1	37.9
HELIRF	INTER-REG'L ELEC. TRANSFERS	247.5	297.6	217.7	224.6	274.1	305.9	443.9	443.9	443.9	443.9
HTSPCF	PRODUCER CONSUMPTION	35.1	40.6	39.6	41.6	44.5	48.9	51.0	57.3	62.3	78.3
HTSCLF	INTERMEDIATE CONVERSION LOSS	214.2	245.7	248.3	258.4	272.6	301.8	327.2	369.3	428.2	569.4
HTSPDF	PRIMARY DEMAND BY FUEL - TOTAL	988.0	1092.6	1040.6	1071.2	1152.2	1258.7	1476.3	1582.4	1714.0	2035.4
HRPPDF	RPP'S	425.9	474.3	443.3	469.8	508.6	554.8	566.3	638.2	668.3	816.8
HNGPDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.8	0.8	0.8	0.8	0.8
HLPPDF	LPG'S	5.4	6.5	6.9	7.1	7.4	8.7	9.7	10.5	11.5	14.1
HCCPDF	COAL	85.4	91.0	100.5	103.0	105.8	193.7	202.0	224.7	274.8	349.2
HENPDF	NUCLEAR ELECTRICITY	53.7	56.7	49.7	49.6	49.7	49.8	83.1	83.8	84.1	176.4
HEHPDF	HYDRO ELECTRICITY	366.4	407.2	380.1	381.1	419.4	387.1	546.6	552.1	597.8	592.4
HOFPDF	OTHER (RENEWABLES)	51.3	56.9	59.9	60.6	61.3	63.8	67.8	72.3	76.6	85.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2F	PRIMARY DEMAND - TOTAL	712.0	787.8	758.1	788.1	843.9	971.7	1062.5	1164.5	1265.9	1530.2
HEHP2F	HYDRO ELECTRICITY	125.6	139.6	130.3	130.7	143.8	132.7	187.4	189.3	205.0	203.1
HENP2F	NUCLEAR ELECTRICITY	18.4	19.4	17.0	17.0	17.1	17.1	28.5	28.7	28.8	60.5
	RATIOS:										
RRDPHF	RES. DEMAND / HOUSEHOLD (GJ)	107.38	111.02	112.31	113.61	114.80	116.08	115.83	116.94	119.95	125.00
RCDPRF	COM. DEMAND / COM. RDP	4.17	4.00	4.07	4.11	4.15	4.24	4.29	4.32	4.34	4.37
RIDPRF	IND. DEMAND / IND. RDP	24.90	24.63	24.28	24.26	24.26	24.10	23.46	22.87	22.81	22.86
RSDPCF	SECONDARY DEMAND / POP (GJ).	205.10	211.49	221.42	225.23	230.06	242.84	259.87	280.10	304.82	365.62
RSDPRF	" " / RDP/	19.82	19.68	20.26	20.40	20.22	20.20	19.87	19.44	19.17	18.99
REUPCF	END-USE DEMAND / POP (GJ)	214.89	221.66	232.21	236.38	241.45	254.65	272.04	292.83	318.34	380.92
REUPRF	" " / RDP	20.77	20.62	21.24	21.40	21.22	21.18	20.80	20.32	20.02	19.79
RPDPCF	PRIMARY DEMAND / POP (GJ)	432.28	476.15	451.71	463.30	495.90	532.33	613.91	650.89	699.85	821.41
RPDPRF	" " / RDP	41.78	44.30	41.32	41.95	43.58	44.28	46.95	45.17	44.01	42.66

TABLE C.9.3: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: QUEBEC

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
HTSSDQ	SECONDARY DEMAND BY FUEL:	1331.2	1397.6	1419.9	1445.0	1494.2	1640.1	1836.3	2080.0	2346.6	3024.2
HRPSDQ	RPP'S	521.2	559.7	571.2	581.2	598.4	643.9	698.8	763.1	840.2	1043.6
HNGSDQ	NATURAL GAS	189.3	195.2	195.6	200.3	211.6	240.4	276.9	313.9	354.3	457.8
HELSDQ	ELECTRICITY	525.6	536.9	549.7	561.4	581.4	652.1	750.7	882.7	1020.9	1365.6
HCCSDQ	COAL	14.8	17.0	15.2	14.0	13.4	11.6	11.8	13.6	15.9	22.3
HLPSDQ	LPG'S	9.6	16.0	15.2	14.6	14.2	13.0	12.2	12.4	13.1	15.3
HKGSDQ	COKE AND COKE OVEN GAS	2.5	2.6	2.6	2.6	2.6	2.8	3.0	3.4	3.7	4.5
HSTSDQ	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDQ	OTHER	68.3	70.1	70.3	70.9	72.6	76.4	82.9	90.8	98.5	115.2
	PRIMARY DEMAND BY SECTOR:										
HTSPDQ	TOTAL	2417.9	2477.5	2653.0	2685.3	2696.8	2980.6	3414.9	3974.0	4571.3	6068.9
HTSEUQ	END-USE DEMAND	1426.7	1518.7	1547.5	1576.2	1629.8	1788.4	1995.8	2253.6	2535.3	3241.8
HTSSDQ	SECONDARY DEMAND	1331.2	1397.6	1419.9	1445.0	1494.2	1640.1	1836.3	2080.0	2346.6	3024.2
HTSRAQ	RESIDENTIAL	257.9	269.0	271.1	273.0	275.7	286.4	293.7	304.5	319.5	364.8
HTSCPQ	COMMERCIAL	177.1	184.2	190.0	194.0	198.9	220.2	247.3	275.9	300.3	355.3
HTSINQ	INDUSTRIAL	537.5	566.8	571.6	582.1	610.2	685.9	807.2	968.9	1143.6	1584.9
HTSTRQ	TRANSPORTATION	359.1	377.6	387.3	395.9	409.4	447.5	488.0	530.7	583.3	719.2
HTSNEQ	NON-ENERGY USE	95.5	121.1	127.6	131.2	135.6	148.3	159.5	173.7	188.6	217.6
HELIRQ	INTER-REG'L ELEC. TRANSFERS.	-185.3	-274.0	-154.8	-177.6	-265.7	-305.9	-307.4	-307.4	-307.4	-307.4
HTSPCQ	PRODUCER CONSUMPTION	87.1	96.6	98.2	100.1	103.7	117.6	133.5	152.9	173.7	226.8
HTSCLQ	INTERMEDIATE CONVERSION LOSS	1089.4	1136.3	1162.1	1186.6	1228.9	1380.5	1593.0	1874.8	2169.7	2907.6
HTSPDQ	PRIMARY DEMAND BY FUEL - TOTAL.	2417.9	2477.5	2653.0	2685.3	2696.8	2980.6	3414.9	3974.0	4571.3	6068.9
HRPPDQ	RPP'S	646.5	705.2	724.6	737.7	760.4	859.1	939.2	1017.4	1109.8	1364.9
HNGPDQ	NATURAL GAS	192.7	203.9	204.3	209.0	220.6	249.9	287.0	324.7	365.8	471.1
HLPPDQ	LPG'S	12.2	24.5	23.7	23.1	22.7	29.0	32.4	37.3	41.9	47.4
HCCPDQ	COAL	24.4	27.1	25.4	24.2	23.8	22.5	23.7	26.7	30.2	39.1
HENPDQ	NUCLEAR ELECTRICITY	48.9	55.8	55.8	55.8	55.8	55.8	56.5	57.1	51.3	881.4
HEHPDQ	HYDRO ELECTRICITY	1424.9	1390.9	1549.0	1564.6	1541.0	1687.9	1993.2	2420.0	2873.9	3149.7
HOFPDQ	OTHER (RENEWABLES)	68.3	70.1	70.3	70.9	72.6	76.4	82.9	90.8	98.5	115.2
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2Q	PRIMARY DEMAND - TOTAL	1449.4	1526.9	1598.5	1620.5	1647.5	1834.8	2067.9	2346.2	2649.1	3419.8
HEHP2Q	HYDRO ELECTRICITY	488.6	476.9	531.1	536.4	528.3	578.7	683.4	829.7	985.3	1079.9
HENP2Q	NUCLEAR ELECTRICITY	16.8	19.1	19.1	19.1	19.1	19.1	19.4	19.6	17.6	302.2
	RATIOS:										
RRDPHQ	RES. DEMAND / HOUSEHOLD (GJ)	98.46	101.64	101.27	100.83	100.20	99.20	96.17	93.75	92.34	93.12
RCDPRQ	COM. DEMAND / COM. RDP	3.61	3.59	3.62	3.64	3.67	3.73	3.77	3.78	3.79	3.80
RIDPRQ	IND. DEMAND / IND. RDP	20.16	20.17	20.23	20.29	20.31	20.59	20.64	20.67	20.75	21.07
RSDPCQ	SECONDARY DEMAND / POP (GJ).	202.01	210.62	212.29	214.32	219.57	232.74	251.09	275.54	302.46	375.72
RSDPRQ	" " / RDP/	15.66	15.72	15.63	15.64	15.56	15.67	15.59	15.58	15.63	16.06
REUPCQ	END-USE DEMAND / POP (GJ)	216.51	228.86	231.36	233.78	239.50	253.79	272.91	298.55	326.77	402.76
REUPRQ	" " / RDP	16.78	17.08	17.03	17.06	16.98	17.09	16.95	16.88	16.89	17.21
RPDPCQ	PRIMARY DEMAND / POP (GJ)	366.93	373.36	396.64	398.28	396.29	422.97	466.96	526.44	589.20	753.99
RPDPRQ	" " / RDP	28.44	27.87	29.20	29.06	28.09	28.48	29.00	29.77	30.45	32.22

TABLE C.9.4: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: ONTARIO

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDO	SECONDARY DEMAND BY FUEL:	2214.4	2347.5	2399.9	2452.9	2556.5	2912.8	3359.2	3800.0	4255.3	5441.5
HRPSDO	RPP'S	775.7	807.9	824.3	840.4	866.6	972.4	1087.5	1213.1	1354.8	1719.9
HNGSDO	NATURAL GAS	682.3	742.4	764.7	787.6	827.8	947.6	1093.3	1251.6	1422.0	1839.7
HELSDO	ELECTRICITY	444.8	472.6	485.2	498.0	522.6	620.6	763.4	878.5	970.3	1252.3
HCCSDO	COAL	22.0	21.6	21.6	21.7	23.5	27.1	33.3	39.8	46.6	64.6
HLPSDO	LPG'S	29.2	25.7	25.4	25.8	26.5	31.0	30.2	23.3	25.3	30.0
HKGSDO	COKE AND COKE OVEN GAS	163.9	171.5	172.6	172.6	177.8	191.5	212.3	236.1	260.1	313.7
HSTSDO	STEAM	25.8	32.6	32.5	32.7	35.4	40.9	50.2	60.0	70.3	97.4
HOFSDO	OTHER	70.6	73.3	73.6	74.1	76.2	81.5	89.1	97.6	105.9	123.8
	PRIMARY DEMAND BY SECTOR:										
HTSPDO	TOTAL	3427.9	3683.5	3742.8	3848.1	4048.2	4668.9	5329.8	6058.0	6759.1	8651.0
HTSEUO	END-USE DEMAND	2464.0	2612.5	2668.2	2724.1	2834.5	3214.6	3694.2	4172.5	4660.4	5914.7
HTSSDO	SECONDARY DEMAND	2214.4	2347.5	2399.9	2452.9	2556.5	2912.8	3359.2	3800.0	4255.3	5441.5
HTSRAO	RESIDENTIAL	461.9	487.0	498.0	508.4	521.2	565.1	611.7	634.3	658.9	752.2
HTSCPO	COMMERCIAL	299.0	315.0	327.1	336.5	349.1	403.4	474.4	550.6	617.3	773.8
HTSINO	INDUSTRIAL	842.0	905.7	923.2	942.9	995.5	1163.9	1394.5	1644.0	1904.2	2566.1
HTSTRO	TRANSPORTATION	611.9	639.9	651.6	665.2	690.7	780.2	878.7	971.1	1075.0	1349.4
HTSNEO	NON-ENERGY USE	249.6	264.9	268.3	271.2	278.1	301.8	335.0	372.5	405.1	473.2
HELIRO	INTER-REG'L ELEC. TRANSFERS	-73.3	-29.0	-66.3	-49.5	-12.5	-5.5	-140.4	-143.6	-147.3	-147.1
HTSPCO	PRODUCER CONSUMPTION	162.2	171.4	176.9	182.5	189.7	225.5	266.3	295.8	324.7	402.9
HTSCLO	INTERMEDIATE CONVERSION LOSS	874.9	928.6	964.1	991.1	1036.4	1234.4	1509.7	1733.3	1921.4	2480.5
HTSPDO	PRIMARY DEMAND BY FUEL - TOTAL	3427.9	3683.5	3742.8	3848.1	4048.2	4668.9	5329.8	6058.0	6759.1	8651.0
HRPPDO	RPP'S	1038.3	1061.9	1084.2	1104.7	1138.5	1360.7	1620.8	1773.2	1927.5	2347.6
HNGPDO	NATURAL GAS	781.2	870.7	904.6	930.9	975.6	1190.5	1359.0	1541.0	1727.7	2177.7
HLPPDO	LPG'S	58.7	58.4	58.1	58.5	60.1	67.7	70.8	68.2	74.8	90.3
HCCPDO	COAL	520.1	557.7	514.0	506.2	557.8	592.1	783.5	913.4	877.5	1003.8
HENPDO	NUCLEAR ELECTRICITY	662.7	712.2	779.6	844.5	910.2	1043.9	1045.2	1265.7	1646.3	2505.1
HEHPDO	HYDRO ELECTRICITY	296.3	349.3	326.8	326.8	327.3	329.2	358.3	395.8	396.3	399.6
HOFPDO	OTHER (RENEWABLES)	70.6	73.3	75.4	76.4	78.7	84.7	92.2	100.8	109.1	127.0
	ELECTRICITY CONVERTED AT 3.6:										
HTSP20	PRIMARY DEMAND - TOTAL	2797.7	2985.9	3015.8	3078.4	3234.9	3766.6	4407.5	4966.2	5416.9	6742.2
HEHP20	HYDRO ELECTRICITY	101.6	119.8	112.1	112.1	112.2	112.9	122.8	135.7	135.9	137.0
HENP20	NUCLEAR ELECTRICITY	227.2	244.2	267.3	289.5	312.1	357.9	358.3	434.0	564.4	858.9
	RATIOS:										
RRDPHO	RES. DEMAND / HOUSEHOLD (GJ)	129.69	134.15	134.14	134.54	134.99	137.17	137.72	132.09	126.88	124.02
RCDPRO	COM. DEMAND / COM. RDP	3.51	3.54	3.59	3.64	3.68	3.79	3.86	3.89	3.89	3.90
RIDPRO	IND. DEMAND / IND. RDP	16.48	16.46	16.63	16.77	16.76	17.13	17.23	16.95	16.69	16.49
RSDPCO	SECONDARY DEMAND / POP (GJ).	238.97	249.17	250.94	252.88	259.79	281.12	306.39	330.53	355.20	425.26
RSDPRO	" " / RDP/	14.86	14.99	14.99	15.07	14.98	15.10	14.79	14.10	13.58	12.94
REUPCO	END-USE DEMAND / POP (GJ)	265.91	277.29	278.99	280.84	288.04	310.25	336.94	362.93	389.01	462.24
REUPRO	" " / RDP	16.54	16.68	16.67	16.73	16.61	16.66	16.26	15.49	14.87	14.06
RPDPCO	PRIMARY DEMAND / POP (GJ)	369.92	390.97	391.35	396.71	411.38	450.62	486.12	526.94	564.20	676.09
RPDPRO	" " / RDP	23.01	23.52	23.38	23.64	23.72	24.20	23.46	22.49	21.56	20.57

TABLE C.9.5: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: MANITOBA

				FORECAST							
		1987	1988	1989	1990	1991	1995	2000	2005	2010	2020
HTSSDM	SECONDARY DEMAND BY FUEL:	202.5	211.0	218.1	223.0	229.2	250.1	274.7	296.6	319.5	388.0
HRPSDM	RPP'S	95.8	98.9	102.2	104.9	109.0	121.8	134.7	146.7	159.5	190.8
HNGSDM	NATURAL GAS	51.3	56.2	57.8	58.5	59.3	62.5	65.8	68.2	70.9	78.6
HELSDM	ELECTRICITY	49.3	51.2	53.6	55.0	56.3	61.1	69.0	76.0	82.9	110.9
HCCSDM	COAL	2.5	2.2	2.2	2.1	2.0	1.8	1.9	2.1	2.3	3.0
HLPSDM	LPG'S	2.9	2.0	1.7	1.9	1.9	2.1	2.3	2.6	2.9	3.6
HKGSDM	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1
HSTSDM	STEAM	0.3	0.3	0.3	0.3	0.3	0.4	0.5	0.5	0.5	0.6
HOFSDM	OTHER	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.5
	PRIMARY DEMAND BY SECTOR:										
HTSPDM	TOTAL	356.7	378.4	388.3	397.6	409.9	449.1	495.0	540.4	586.3	732.1
HTSEUM	END-USE DEMAND	214.4	223.1	230.7	236.1	242.8	264.9	290.0	312.6	336.3	406.5
HTSSDM	SECONDARY DEMAND	202.5	211.0	218.1	223.0	229.2	250.1	274.7	296.6	319.5	388.0
HTSRAM	RESIDENTIAL	54.6	62.0	63.9	65.5	67.0	71.4	75.7	78.2	81.4	97.2
HTSCPM	COMMERCIAL	40.5	40.6	42.4	43.7	45.0	50.1	55.6	60.6	64.5	73.1
HTSINM	INDUSTRIAL	33.4	35.4	37.1	37.3	37.7	39.6	44.7	50.8	57.6	78.0
HTSTRM	TRANSPORTATION	74.0	73.1	74.7	76.5	79.4	89.0	98.8	107.0	116.0	139.7
HTSNEM	NON-ENERGY USE	11.9	12.0	12.5	13.1	13.7	14.8	15.4	16.0	16.8	18.5
HELIRM	INTER-REG'L ELEC. TRANSFERS	11.5	8.2	4.4	3.6	5.1	6.6	4.9	8.1	11.9	11.7
HTSPCM	PRODUCER CONSUMPTION	20.1	26.7	27.8	29.3	30.4	34.8	38.8	42.3	45.7	56.5
HTSCLM	INTERMEDIATE CONVERSION LOSS	110.7	120.5	125.4	128.5	131.6	142.8	161.2	177.5	192.4	257.4
HTSPDM	PRIMARY DEMAND BY FUEL - TOTAL	356.7	378.4	388.3	397.6	409.9	449.1	495.0	540.4	586.3	732.1
HRPPDM	RPP'S	101.1	104.5	108.6	111.9	116.5	130.5	144.0	156.6	170.2	203.3
HNGPDM	NATURAL GAS	70.9	79.5	81.8	83.8	85.4	92.0	97.7	102.1	106.9	119.7
HLPPDM	LPG'S	2.9	2.0	1.8	1.9	2.0	2.2	2.4	2.7	3.0	3.7
HCCPDM	COAL	9.7	13.9	8.4	8.3	8.3	8.2	8.4	8.5	3.1	3.9
HENPDM	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	44.1	46.9
HEHPDM	HYDRO ELECTRICITY	171.8	177.9	187.0	191.0	197.1	215.5	241.7	269.8	258.1	353.8
HOFPDM	OTHER (RENEWABLES)	0.3	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.8
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2M	PRIMARY DEMAND - TOTAL	243.8	261.5	265.4	272.1	280.4	307.5	336.2	363.2	387.6	468.8
HEHP2M	HYDRO ELECTRICITY	58.9	61.0	64.1	65.5	67.6	73.9	82.9	92.5	88.5	121.3
HENP2M	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.1	16.1
	RATIOS:										
RRDPHM	RES. DEMAND / HOUSEHOLD (GJ)	108.08	121.65	122.08	122.65	122.81	124.22	125.13	121.29	117.88	124.44
RCDPRM	COM. DEMAND / COM. RDP	4.64	4.69	4.80	4.90	4.99	5.23	5.38	5.43	5.46	5.49
RIDPRM	IND. DEMAND / IND. RDP	10.19	10.36	10.16	10.00	9.87	9.51	9.38	9.25	9.21	9.74
RSDPCM	SECONDARY DEMAND / POP (GJ)	187.89	194.14	199.11	202.10	205.90	217.95	231.64	242.69	253.70	291.64
RSDPRM	" " / RDP/	13.60	13.88	13.87	13.90	13.74	13.71	13.33	12.65	12.10	11.68
REUPCM	END-USE DEMAND / POP (GJ)	198.91	205.22	210.56	213.95	218.18	230.84	244.62	255.77	267.00	305.56
REUPRM	" " / RDP	14.40	14.68	14.67	14.72	14.56	14.52	14.07	13.33	12.73	12.23
RPDPCM	PRIMARY DEMAND / POP (GJ)	330.87	348.15	354.46	360.26	368.29	391.40	417.49	442.25	465.47	550.26
RPDPRM	" " / RDP	23.95	24.90	24.69	24.78	24.57	24.62	24.02	23.05	22.20	22.03

TABLE C.9.6: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: SASKATCHEWAN

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
HTSSDS	SECONDARY DEMAND BY FUEL:	268.9	273.9	277.3	279.5	286.3	311.6	351.8	396.6	438.1	537.7
HRPSDS	RPP'S	122.3	118.7	120.6	122.0	125.2	137.7	157.2	176.6	195.7	239.9
HNGSDS	NATURAL GAS	87.4	95.6	96.9	97.6	99.7	106.2	114.2	122.3	133.9	167.7
HELSDS	ELECTRICITY	39.9	43.5	43.3	43.1	43.8	48.0	57.9	71.8	79.3	93.7
HCCSDS	COAL	4.8	3.9	4.3	4.5	5.0	6.3	8.0	9.9	11.8	16.1
HLPSDS	LPG'S	3.6	1.1	1.0	1.0	1.0	1.1	1.1	1.2	1.4	1.6
HKGSDS	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDS	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDS	OTHER	10.9	11.2	11.3	11.4	11.6	12.4	13.4	14.7	16.0	18.7
	PRIMARY DEMAND BY SECTOR:										
HTSPDS	TOTAL	416.4	435.7	441.2	446.0	457.3	502.8	578.0	664.8	725.7	875.8
HTSEUS	END-USE DEMAND	280.3	286.3	290.7	293.5	300.9	327.9	369.4	416.0	459.6	564.2
HTSSDS	SECONDARY DEMAND	268.9	273.9	277.3	279.5	286.3	311.6	351.8	396.6	438.1	537.7
HTSRAS	RESIDENTIAL	85.5	92.1	93.1	94.1	95.7	100.5	105.9	111.0	115.4	127.8
HTSCPS	COMMERCIAL	40.1	38.8	39.2	39.2	39.6	41.8	45.3	49.4	52.8	60.8
HTSINS	INDUSTRIAL	69.8	72.2	74.3	75.7	79.6	91.9	110.1	133.5	156.3	210.4
HTSTRS	TRANSPORTATION	73.6	70.7	70.7	70.5	71.3	77.4	90.5	102.7	113.6	138.7
HTSNES	NON-ENERGY USE	11.4	12.4	13.3	14.0	14.7	16.2	17.6	19.4	21.5	26.5
HELIRS	INTER-REG'L ELEC. TRANSFERS	-0.4	-2.7	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
HTSPCS	PRODUCER CONSUMPTION	34.2	47.5	48.5	51.1	53.1	61.4	68.7	75.4	81.5	96.3
HTSCLS	INTERMEDIATE CONVERSION LOSS	102.4	104.5	103.1	102.5	104.4	114.6	140.9	174.5	185.6	216.4
HTSPDS	PRIMARY DEMAND BY FUEL - TOTAL	416.4	435.7	441.2	446.0	457.3	502.8	578.0	664.8	725.7	875.8
HRPPDS	RPP'S	139.5	136.3	139.2	141.2	145.2	159.8	181.5	203.4	225.5	276.5
HNGPDS	NATURAL GAS	119.2	139.9	143.0	146.3	151.0	164.9	185.1	203.0	218.9	268.8
HLPPDS	LPG'S	3.7	1.1	1.0	1.0	1.0	1.1	1.1	1.3	1.4	1.6
HCCPDS	COAL	115.3	118.2	111.5	110.9	113.1	128.9	160.9	180.8	127.9	111.8
HENPDS	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	63.6	126.5
HEHPDS	HYDRO ELECTRICITY	33.2	27.3	33.5	33.5	33.6	33.7	33.9	59.6	70.3	70.0
HOFPDS	OTHER (RENEWABLES)	10.9	12.8	13.0	13.2	13.5	14.3	15.4	16.7	18.0	20.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2S	PRIMARY DEMAND - TOTAL	399.9	417.7	419.2	424.0	435.3	480.6	555.7	625.7	637.7	746.7
HEHP2S	HYDRO ELECTRICITY	11.4	9.4	11.5	11.5	11.5	11.6	11.6	20.4	24.1	24.0
HENP2S	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	21.8	43.4
	RATIOS:										
RRDPHS	RES. DEMAND / HOUSEHOLD (GJ)	144.02	158.44	156.96	156.18	155.61	154.62	154.56	152.37	146.85	140.63
RCDPRS	COM. DEMAND / COM. RDP	5.99	5.85	5.77	5.71	5.66	5.54	5.46	5.42	5.39	5.37
RIDPRS	IND. DEMAND / IND. RDP	19.02	18.71	18.82	18.93	19.01	19.40	19.79	20.04	19.94	19.68
RSDPCS	SECONDARY DEMAND / POP (GJ)	265.57	269.00	270.98	271.54	276.03	291.67	319.06	349.38	375.10	438.43
RSDPRS	" " / RDP/	17.90	18.65	17.68	17.37	17.14	17.19	17.34	17.34	17.13	16.94
REUPCS	END-USE DEMAND / POP (GJ)	276.79	281.22	284.01	285.15	290.17	306.85	335.05	366.46	393.52	460.04
REUPRS	" " / RDP	18.66	19.50	18.53	18.25	18.02	18.09	18.21	18.19	17.97	17.77
RPDPCS	PRIMARY DEMAND / POP (GJ)	411.20	427.87	431.09	433.31	440.99	470.56	524.19	585.69	621.29	714.13
RPDPRS	" " / RDP	27.72	29.67	28.13	27.72	27.39	27.74	28.49	29.07	28.37	27.59

TABLE C.9.7: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES)

REGION: ALBERTA

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
HTSSDA	SECONDARY DEMAND BY FUEL:	778.2	840.5	853.7	855.7	874.5	959.1	1079.2	1210.6	1354.4	1745.1
HRPSDA	RPP'S	308.4	325.4	328.5	327.1	333.8	363.0	412.6	470.4	532.6	676.9
HNGSDA	NATURAL GAS	304.8	340.6	347.2	349.5	356.4	389.3	421.8	455.0	494.8	614.5
HELSDA	ELECTRICITY	120.1	124.8	128.5	129.2	133.4	152.7	189.9	228.0	266.6	383.1
HCCSDA	COAL	0.9	1.3	1.3	1.2	1.2	0.8	0.5	0.4	0.3	0.3
HLPSDA	LPG'S	22.5	25.9	25.5	25.3	26.4	28.3	27.2	27.1	27.7	32.4
HKGSDA	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDA	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDA	OTHER	21.3	22.5	22.8	22.8	23.3	25.1	27.2	29.8	32.4	37.9
	PRIMARY DEMAND BY SECTOR:										
HTSPDA	TOTAL	1485.7	1562.0	1604.9	1609.2	1641.4	1825.5	2125.2	2406.5	2715.0	3417.5
HTSEUA	END-USE DEMAND	1128.7	1213.6	1229.9	1233.4	1264.0	1396.5	1605.6	1795.7	2007.7	2433.5
HTSSDA	SECONDARY DEMAND	778.2	840.5	853.7	855.7	874.5	959.1	1079.2	1210.6	1354.4	1745.1
HTSRAA	RESIDENTIAL	182.4	205.9	208.3	211.2	215.4	231.8	247.4	257.9	272.4	323.6
HTSCPA	COMMERCIAL	126.1	133.2	139.8	143.7	145.2	155.2	170.3	187.7	203.2	241.4
HTSINA	INDUSTRIAL	241.6	265.4	269.9	266.1	274.9	311.0	362.8	427.1	498.9	701.4
HTSTRA	TRANSPORTATION	228.9	236.2	235.7	234.8	239.0	261.1	298.8	337.9	379.8	478.7
HTSNEA	NON-ENERGY USE	350.6	373.1	376.2	377.6	389.5	437.4	526.4	585.1	653.3	688.4
HELIRA	INTER-REG'L ELEC. TRANSFERS	1.9	8.9	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
HTSPCA	PRODUCER CONSUMPTION	68.6	76.0	77.8	78.9	80.5	90.7	103.7	116.3	129.8	162.9
HTSCLA	INTERMEDIATE CONVERSION LOSS	286.4	263.4	291.4	291.2	291.1	332.5	410.1	488.8	571.7	815.3
HTSPDA	PRIMARY DEMAND BY FUEL - TOTAL	1485.7	1562.0	1604.9	1609.2	1641.4	1825.5	2125.2	2406.5	2715.0	3417.5
HRPPDA	RPP'S	397.6	421.0	426.7	426.6	435.6	481.0	548.8	618.3	694.2	870.5
HNGPDA	NATURAL GAS	567.5	636.8	711.0	705.4	666.7	726.3	823.7	907.3	972.6	1103.5
HLPPDA	LPG'S	118.5	126.6	126.2	126.6	133.2	159.2	178.4	178.2	229.2	233.9
HCCPDA	COAL	365.4	341.2	293.4	301.7	355.5	402.8	514.0	550.3	585.1	969.0
HENPDA	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDA	HYDRO ELECTRICITY	15.3	13.9	14.8	14.7	14.7	14.3	14.3	103.8	182.7	183.9
HOFPDA	OTHER (RENEWABLES)	21.3	22.5	32.8	34.2	35.7	41.8	46.0	48.6	51.2	56.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2A	PRIMARY DEMAND - TOTAL	1475.5	1552.8	1595.1	1599.5	1631.7	1816.1	2115.8	2338.3	2594.9	3296.6
HEHP2A	HYDRO ELECTRICITY	5.2	4.8	5.1	5.0	5.1	4.9	4.9	35.6	62.7	63.0
HENP2A	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHA	RES. DEMAND / HOUSEHOLD (GJ)	171.06	194.16	192.41	191.33	190.30	187.54	181.77	171.60	164.83	165.18
RCDPRA	COM. DEMAND / COM. RDP	6.00	6.08	6.00	5.94	5.88	5.74	5.63	5.55	5.50	5.49
RIDPRA	IND. DEMAND / IND. RDP	13.10	12.92	12.76	12.64	12.52	12.24	12.10	11.89	11.81	12.17
RSDPCA	SECONDARY DEMAND / POP (GJ)	327.19	351.62	353.74	350.10	351.64	356.85	369.83	387.23	408.16	479.00
RSDPRA	" " / RDP/	17.06	17.48	17.35	17.32	17.02	17.04	16.94	16.67	16.53	16.88
REUPCA	END-USE DEMAND / POP (GJ)	474.60	507.69	509.63	504.59	508.26	519.58	550.20	574.38	605.04	667.95
REUPRA	" " / RDP	24.75	25.24	24.99	24.97	24.60	24.81	25.20	24.72	24.50	23.54
RPDPCA	PRIMARY DEMAND / POP (GJ)	624.68	653.42	665.02	658.36	660.00	679.18	728.24	769.78	818.21	938.04
RPDPRA	" " / RDP	32.57	32.48	32.61	32.57	31.94	32.43	33.36	33.13	33.14	33.05

TABLE C.9.8: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES)

REGION: B.C.+YK.+N.W.T.

		1987	1988	FORECAST 1989	1990	1991	1995	2000	2005	2010	2020
HTSSDZ	SECONDARY DEMAND BY FUEL:	834.1	873.2	883.6	895.7	923.2	1008.8	1120.9	1247.3	1379.8	1710.9
HRPSDZ	RPP'S	308.4	322.6	328.7	328.7	338.2	366.7	405.5	453.3	507.3	643.8
HNGSDZ	NATURAL GAS	154.9	168.1	169.7	184.0	191.0	210.7	229.9	250.3	271.8	323.5
HELSDZ	ELECTRICITY	170.4	176.6	178.6	175.2	181.2	205.4	239.4	273.6	307.6	400.3
HCCSDZ	COAL	2.6	2.3	2.2	2.2	2.1	2.3	2.7	3.2	3.7	5.1
HLPSDZ	LPG'S	12.5	12.8	13.1	13.5	14.1	16.7	19.6	21.5	23.0	26.9
HKGSDZ	COKE AND COKE OVEN GAS	1.2	1.2	1.2	1.2	1.3	1.3	1.4	1.6	1.8	2.1
HSTSDZ	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDZ	OTHER	184.1	189.4	190.0	190.8	195.2	205.7	222.4	243.7	264.5	309.3
	PRIMARY DEMAND BY SECTOR:										
HTSPDZ	TOTAL	1293.0	1331.7	1354.7	1361.2	1404.3	1549.8	1742.9	1964.2	2178.8	2723.7
HTSEUZ	END-USE DEMAND	890.1	929.8	941.5	954.6	983.1	1071.0	1185.5	1315.3	1451.6	1792.3
HTSSDZ	SECONDARY DEMAND	834.1	873.2	883.6	895.7	923.2	1008.8	1120.9	1247.3	1379.8	1710.9
HTSRAZ	RESIDENTIAL	112.1	125.0	128.4	132.3	136.9	154.4	167.7	174.7	182.6	206.8
HTSCPZ	COMMERCIAL	101.5	104.7	108.3	111.2	115.0	130.2	147.9	165.7	180.6	214.1
HTSINZ	INDUSTRIAL	396.9	409.9	408.0	408.7	420.3	452.5	506.4	576.6	650.8	835.6
HTSTRZ	TRANSPORTATION	224.4	233.6	238.9	243.5	250.9	271.7	298.9	330.3	365.9	454.5
HTSNEZ	NON-ENERGY USE	56.0	56.7	57.9	58.9	60.0	62.2	64.6	68.0	71.8	81.4
HELIRZ	INTER-REG'L ELEC. TRANSFERS	-2.0	-9.0	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8	-5.8
HTSPCZ	PRODUCER CONSUMPTION	62.8	53.0	52.9	53.5	55.3	61.7	68.6	76.9	84.3	102.5
HTSCLZ	INTERMEDIATE CONVERSION LOSS	342.0	357.8	366.1	359.0	371.6	422.9	494.6	577.8	648.6	834.6
HTSPDZ	PRIMARY DEMAND BY FUEL - TOTAL	1293.0	1331.7	1354.7	1361.2	1404.3	1549.8	1742.9	1964.2	2178.8	2723.7
HRPPDZ	RPP'S	363.4	384.0	391.2	392.0	403.5	437.5	480.5	533.2	596.4	749.7
HNGPDZ	NATURAL GAS	206.6	216.4	214.7	229.8	237.6	259.5	280.1	329.8	349.0	383.1
HLPPDZ	LPG'S	12.9	13.4	13.7	14.2	14.7	17.4	20.3	22.3	23.5	27.4
HCCPDZ	COAL	7.1	3.7	3.6	3.5	3.5	3.8	4.2	47.9	43.6	14.8
HENPDZ	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDZ	HYDRO ELECTRICITY	519.1	524.7	531.3	519.5	537.7	611.7	720.8	772.8	887.3	1224.8
HOFPDZ	OTHER (RENEWABLES)	184.1	189.4	200.2	202.2	207.3	220.0	237.0	258.3	279.0	323.8
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2Z	PRIMARY DEMAND - TOTAL	952.0	986.9	1005.6	1019.8	1051.0	1147.8	1269.2	1456.4	1595.7	1918.8
HEHP2Z	HYDRO ELECTRICITY	178.0	179.9	182.2	178.1	184.3	209.7	247.1	265.0	304.2	419.9
HENP2Z	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHZ	RES. DEMAND / HOUSEHOLD (GJ)	92.75	102.37	103.30	104.67	106.03	110.63	109.75	104.59	100.35	96.30
RCDPRZ	COM. DEMAND / COM. RDP	4.26	4.23	4.30	4.37	4.44	4.61	4.70	4.72	4.73	4.73
RIDPRZ	IND. DEMAND / IND. RDP	27.93	27.27	26.98	26.79	26.33	25.57	24.49	23.27	22.33	21.02
RSDPCZ	SECONDARY DEMAND / POP (GJ)	277.85	287.25	286.59	286.25	290.10	296.52	306.17	320.81	337.56	386.54
RSDPRZ	" " / RDP/	18.86	18.79	18.67	18.71	18.57	18.65	18.46	18.16	17.92	17.82
REUPCZ	END-USE DEMAND / POP (GJ)	296.50	305.90	305.37	305.06	308.94	314.80	323.82	338.30	355.12	404.93
REUPRZ	" " / RDP	20.13	20.01	19.90	19.94	19.77	19.80	19.52	19.15	18.85	18.67
RPDPCZ	PRIMARY DEMAND / POP (GJ)	430.71	438.10	439.37	435.03	441.29	455.54	476.08	505.21	533.00	615.34
RPDPRZ	" " / RDP	29.24	28.65	28.63	28.43	28.24	28.65	28.70	28.60	28.30	28.37